2. Energy

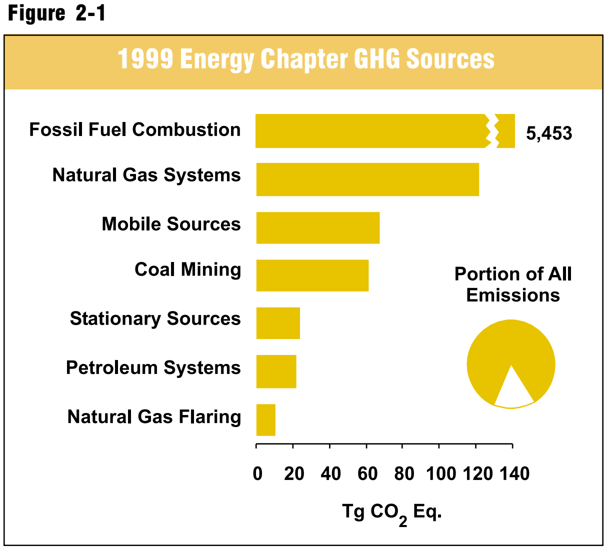
Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 85 percent of total emissions on a carbon equivalent basis in 1999. This included 98, 35, and 18 percent of the nation's carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 81 percent of national emissions from all sources on a carbon equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 2-1). Due to the relative importance of fossil fuel combustion-related CO_2 emissions, they are considered separately from other emissions. Fossil fuel combustion also emits CH_4 and N_2O, as well as criteria pollutants such as nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). Mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States, and overall energy-related activities were collectively the largest source of criteria pollutant emissions.

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of CH_4 from natural gas systems, petroleum systems, and coal mining. Smaller quantities of CO_2, CO, NMVOCs, and NO_x are also emitted.

The combustion of biomass and biomass-based fuels also emits greenhouse gases. Carbon dioxide emissions from these activities, however, are not included in national emissions totals in the Energy chapter because biomass fuels are of biogenic origin. It is assumed that the carbon released when biomass is consumed is recycled as U.S. forests and crops regenerate, causing no net addition of CO_2 to the atmosphere. The net impacts of land-use and forestry activities on the carbon cycle are accounted for in the Land-Use Change and Forestry chapter. Emissions of other greenhouse gases from the combustion of biomass and biomass based fuels are included in national totals under stationary and mobile combustion.

Figure 2-1



Overall, emissions from energy-related activities have increased from 1990 to 1999 due, in part, to the strong performance of the U.S. economy. Over this period, the U.S. Gross Domestic Product (GDP) grew approximately 32 percent, or at an average annual rate of 3.7 percent. This

Table 2-1: Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	1990		1995	1996	1997	1998	1999
CO_2	**4,840.8**		**5,134.8**	**5,316.0**	**5,386.9**	**5,397.6**	**5,464.8**
Fossil Fuel Combustion	4,835.7		5,121.3	5,303.0	5,374.9	5,386.8	5,453.1
Natural Gas Flaring	5.1		13.6	13.0	12.0	10.8	11.7
Biomass-Wood*	174.9		193.2	197.0	187.6	187.4	226.3
International Bunker Fuels*	114.0		101.0	102.2	109.8	112.8	107.3
Biomass-Ethanol*	5.7		7.2	5.1	6.7	7.3	7.8
Carbon Stored in Products*	(276.2)		(317.9)	(323.1)	(338.6)	(343.4)	(361.7)
CH_4	**249.7**		**237.0**	**233.0**	**228.2**	**224.1**	**218.2**
Natural Gas Systems	121.2		124.2	125.8	122.7	122.1	121.8
Coal Mining	87.9		74.6	69.3	68.8	66.5	61.8
Petroleum Systems	27.2		24.5	24.0	24.0	23.3	21.9
Stationary Sources	8.5		8.9	9.0	8.1	7.6	8.1
Mobile Sources	5.0		4.9	4.8	4.7	4.6	4.5
International Bunker Fuels*	+		+	+	+	+	+
N_2O	**67.9**		**81.1**	**80.2**	**80.2**	**79.3**	**79.1**
Mobile Sources	54.3		66.8	65.3	65.2	64.2	63.4
Stationary Sources	13.6		14.3	14.9	15.0	15.1	15.7
International Bunker Fuels*	1.0		0.9	0.9	1.0	1.0	1.0
Total	**5,158.4**		**5,452.9**	**5,629.1**	**5,695.4**	**5,700.9**	**5,762.0**

\+ Does not exceed 0.05 Tg CO_2 Eq.
* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

robust economic activity increased the demand for fossil fuels, with an associated increase in greenhouse gas emissions. Table 2-1 summarizes emissions for the Energy chapter in units of teragrams of carbon dioxide equivalents (Tg CO_2 Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 2-2. Overall, emissions due to energy-related activities were 5,762.0 Tg CO_2 Eq. in 1999, an increase of 12 percent since 1990.

Carbon Dioxide Emissions from Fossil Fuel Combustion

Carbon dioxide (CO_2) emissions from fossil fuel combustion grew by 1.2 percent from 1998 to 1999. Mild winter conditions and increased output from nuclear plants in 1999 resulted in a demand for energy derived from fossil fuels that was less than what would have been expected given the strength of the economy and steady growth in population. In 1999, CO_2 emissions from fossil fuel combustion were 5,453.1 Tg CO_2 Eq., or 12.8 percent above emissions in 1990 (see Table 2-3).

Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams would be expected to have proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

Carbon dioxide emissions are also a function of the source of energy and its carbon intensity. The amount of carbon in fuels varies significantly by fuel type. For example, coal contains the highest amount of carbon per

Table 2-2: Emissions from Energy (Gg)

Gas/Source	1990	1995	1996	1997	1998	1999
CO_2	**4,840,810**	**5,134,850**	**5,315,958**	**5,386,939**	**5,397,600**	**5,464,789**
Fossil Fuel Combustion	4,835,688	5,121,263	5,302,961	5,374,913	5,386,762	5,453,088
Natural Gas Flaring	5,121	13,587	12,998	12,026	10,839	11,701
Biomass-Wood*	174,862	193,245	196,973	187,585	187,433	226,287
International Bunker Fuels*	114,001	101,014	102,197	109,788	112,771	107,345
Biomass-Ethanol*	5,701	7,244	5,144	6,731	7,329	7,776
Carbon Stored in Products*	(276,233)	(317,931)	(323,052)	(338,611)	(343,383)	(361,712)
CH_4	**11,891**	**11,284**	**11,096**	**10,868**	**10,669**	**10,388**
Natural Gas Systems	5,772	5,912	5,993	5,841	5,814	5,799
Coal Mining	4,184	3,550	3,301	3,274	3,168	2,944
Petroleum Systems	1,294	1,168	1,143	1,142	1,108	1,044
Stationary Sources	403	422	430	386	361	386
Mobile Sources	237	232	228	225	219	215
International Bunker Fuels*	2	2	2	2	2	2
N_2O	**219**	**262**	**259**	**259**	**256**	**255**
Mobile Combustion	175	215	211	210	207	204
Stationary Combustion	44	46	48	49	49	51
International Bunker Fuels*	3	3	3	3	3	3

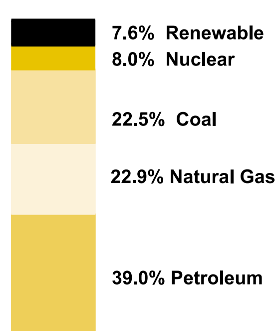
+ Does not exceed 0.05 Gg
* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

unit of useful energy. Petroleum has roughly 75 percent of the carbon per unit of energy as coal, and natural gas has only about 55 percent.[1] Therefore, producing heat or electricity using natural gas instead of coal, for example, can reduce the CO_2 emissions associated with energy consumption, and using nuclear or renewable energy sources (e.g., wind) can essentially eliminate emissions (see Box 2-2).

In the United States, 84 percent of the energy consumed was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 2-2 and Figure 2-3). Of the remaining 16 percent, half was supplied by nuclear electric power and half by a variety of renewable energy sources, primarily hydroelectric power (EIA 2000a). Specifically, petroleum supplied the largest share of domestic energy demands, accounting

Figure 2-2

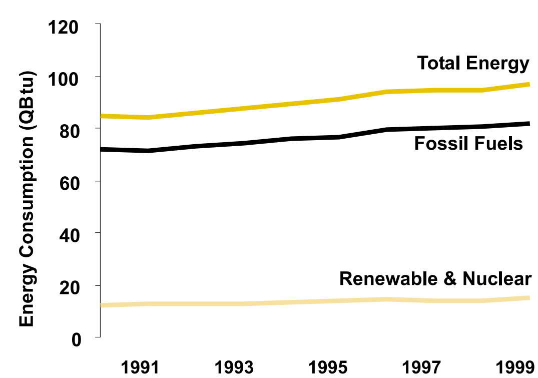
1999 U.S. Energy Consumption by Energy Source



Source: DOE/EIA-0384(99), Annual Energy Review 1998, Table 1.3, July 2000

Figure 2-3

U.S. Energy Consumption (Quadrillion Btu)



Note: Expressed as gross calorific values.
Source: DOE/EIA-0384(97), Annual Energy Review 1999, Table 1.3, July 2000

[1] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

Table 2-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990		1995	1996	1997	1998	1999
Coal	**1,775.9**		**1,867.9**	**1,950.8**	**2,005.6**	**2,015.6**	**2,012.8**
Residential	5.8		5.0	5.1	5.5	4.2	4.2
Commercial	8.7		7.6	7.7	8.2	6.3	6.3
Industrial	251.4		266.6	259.3	261.3	260.2	289.4
Transportation	NE		NE	NE	NE	NE	NE
Electric Utilities	1,509.3		1,587.7	1,677.7	1,729.7	1,744.0	1,711.9
U.S. Territories	0.6		0.9	0.9	1.0	0.9	0.9
Natural Gas	**1,001.9**		**1,154.0**	**1,175.5**	**1,179.8**	**1,139.8**	**1,144.7**
Residential	238.5		263.1	284.6	270.5	246.5	255.0
Commercial	142.4		164.5	171.6	174.7	163.6	166.4
Industrial	433.8		516.2	534.0	533.5	519.0	520.5
Transportation	36.0		38.3	38.9	41.5	34.9	34.8
Electric Utilities	151.1		171.8	146.5	159.6	175.8	168.0
U.S. Territories	NE		NE	NE	NE	NE	NE
Petroleum	**2,057.8**		**2,099.2**	**2,176.5**	**2,189.4**	**2,231.3**	**2,295.6**
Residential	87.7		94.2	100.7	98.9	90.3	95.0
Commercial	66.1		51.8	53.5	50.8	47.6	50.3
Industrial	338.3		318.2	347.2	346.4	334.1	345.6
Transportation	1,435.8		1,541.1	1,579.8	1,587.4	1,621.6	1,679.2
Electric Utilities	96.8		51.0	56.0	64.1	90.8	73.4
U.S. Territories	33.1		43.1	39.1	41.8	47.0	52.1
Geothermal*	**0.2**		**0.1**	**0.1**	**0.1**	**0.1**	**+**
Total	**4,835.7**		**5,121.3**	**5,303.0**	**5,374.9**	**5,386.8**	**5,453.1**

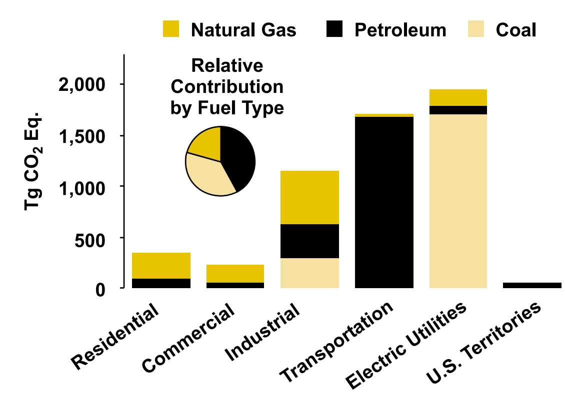
NE (Not estimated)
+ Does not exceed 0.05 Tg CO_2 Eq.
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

for an average of 39 percent of total energy consumption from 1990 through 1999. Natural gas and coal followed in order of importance, each accounting for an average of 23 percent of total consumption. Most petroleum was consumed in the transportation end-use sector, while the vast majority of coal was used by electric utilities, with natural gas broadly consumed in all end-use sectors except transportation (see Figure 2-4) (EIA 2000a).

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process the carbon stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including methane (CH_4), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs).[2] These other carbon containing non-CO_2 gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, except for the soot an

Figure 2-4

1999 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type



Note: Utilities also includes emissions of 0.04 Tg CO_2 Eq. from geothermal based electricity generation

[2] See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO_2 gas emissions from fossil fuel combustion.

Box 2-1: Weather and Non-Fossil Energy Adjustments to CO_2 from Fossil Fuel Combustion Trends

An analysis was performed using EIA's Short-Term Integrated Forecasting System (STIFS) model to examine the effects of variations in weather and output from nuclear and hydroelectric generating plants on U.S. energy-related CO_2 emissions.[3] Weather conditions affect energy demand because of the impact they have on residential, commercial, and industrial end-use sector heating and cooling demands. Warmer winters tend to reduce demand for heating fuels—especially natural gas—while cooler summers tend to reduce air conditioning-related electricity demand. Changes in electricity output from hydroelectric and nuclear power plants do not necessarily affect final energy demand, but increased output from these plants does offset electricity generation by fossil fuel power plants, and therefore leads to reduced CO_2 emissions.

The results of this analysis show that CO_2 emissions from fossil fuel combustion would have been roughly 1.9 percent higher (102 Tg CO_2 Eq.) if weather conditions and hydroelectric and nuclear power generation had achieved normal levels (see Figure 2-5). Similarly, emissions in 1997 and 1998 would have been roughly 0.5 and 1.2 percent (7 and 17 Tg CO_2 Eq.) greater under normal conditions, respectively.

In addition to the absolute level of emissions being greater, the growth rate in CO_2 emissions from fossil fuel combustion from 1998 to 1999 would have been 2.0 percent instead of the actual 1.2 percent if both weather conditions and nonfossil electricity generation had been normal (see Figure 2-6). Similarly, emissions in 1998 would have increased by 0.9 percent under normal conditions versus the actual rate of 0.2 percent.

Figure 2-5

Percent Difference in Adjusted and Actual Energy-Related CO_2 Emissions

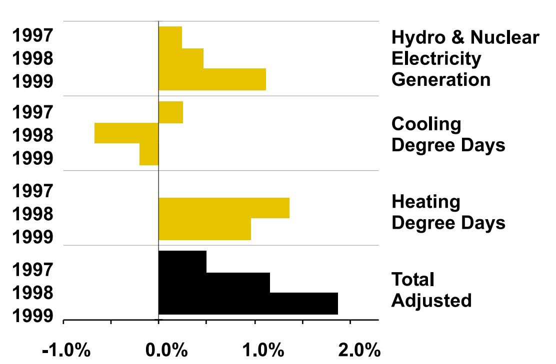
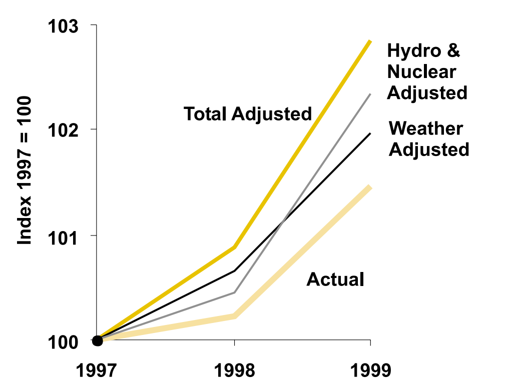


Figure 2-6

Recent Trends in Adjusted and Actual Energy-Related CO_2 Emissions



[3] The STIFS model is employed in producing EIA's *Short-Term Energy Outlook* (DOE/EIA-0202). Complete model documentation can be found at < http://www.eia.doe.gov/emeu/steo/pub/contents.html>. A variety of other factors that influence energy-related CO_2 emissions were also examined such as: changes in output from energy intensive manufacturing industries, and changes in fossil fuel prices for 1997 through 1999. These additional factors, however, were found to have less of an impact on deviations in greenhouse gas emission trends than weather and non0fossil fuel generation fluxuations.

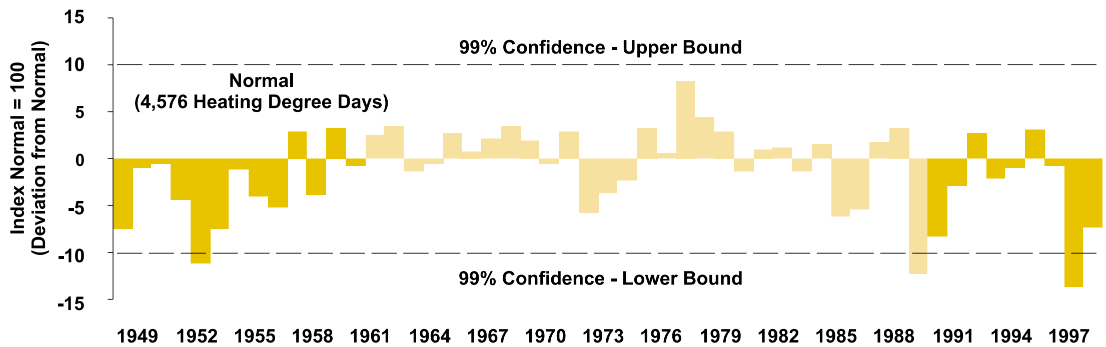
Box 2-1: Weather and Non-Fossil Energy Adjustments to CO_2 from Fossil Fuel Combustion Trends (continued)

Warmer winter conditions in both 1998 and 1999 had a significant effect on U.S. CO_2 emissions by reducing demand for heating fuels. Heating degree days in the United States in 1998 and 1999 were 14 and 7 percent below normal, respectively (see Figure 2-7).[4] These warm winters, however, were partially countered by increased electricity demand that resulted from hotter summers. Cooling degree days in 1998 and 1999 were 18 and 3 percent above normal, respectively (see Figure 2-8).

Although no new U.S. nuclear power plants have been constructed in many years, the utilization (i.e., capacity factors)[5] of existing plants reached record levels in 1998 and 1999, approaching 90 percent. This increase in utilization translated into an increase in electricity output by nuclear plants of slightly more than 7 percent in both years. This increase in nuclear plant output, however, was partially offset by reduced electricity output by hydroelectric power plants, which declined by 10 and 4 percent in 1998 and 1999, respectively. Electricity generated by nuclear plants provides approximately twice as much of the energy consumed in the United States as hydroelectric plants. Nuclear and hydroelectric power plant capacity factors since 1973 are shown in Figure 2-9.

Figure 2-7

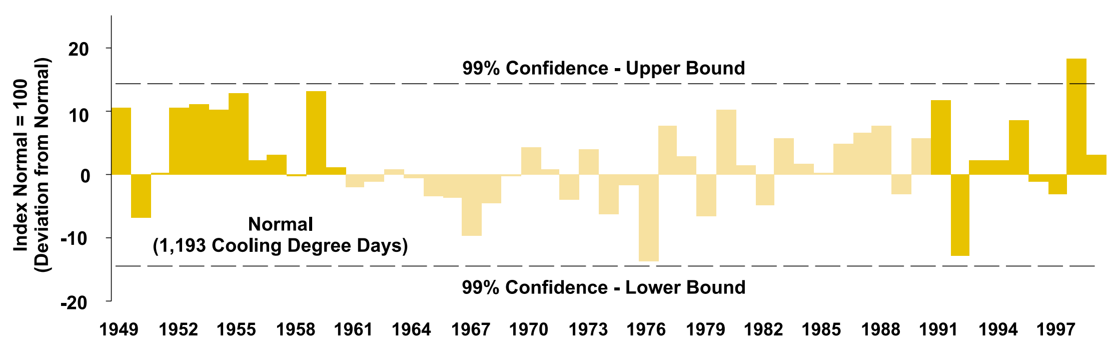
Annual Deviations from Normal Heating Degree Days for the United States (1949-1999)



Note: Climatological normal data is highlighted. Statistical confidence interval for "normal" climatology period of 1961 through 1990.
Source: NOAA (2000b)

Figure 2-8

Annual Deviations from Normal Cooling Degree Days for the United States (1949-1999)



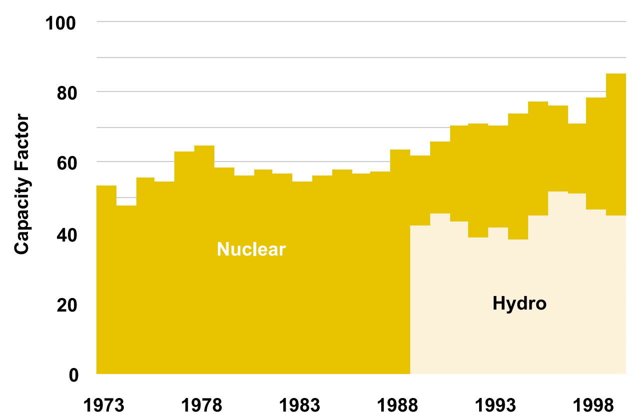
Note: Climatological normal data is highlighted. Statistical confidence interval for "normal" climatology period of 1961 through 1990.
Source: NOAA (2000b)

[4] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1961 through 1990. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

[5] The capacity factor is defined as the ratio of the electrical energy produced by a generating unit for a given period of time to the electrical energy that could have been produced at continuous full- power operation during the same period (DOE/EIA 2000).

Figure 2-9

Nuclear and Hydroelectric Power Plant Capacity Factors in the United States (1973-1999)



ash left behind during the combustion process, all the carbon in fossil fuels used to produce energy is generally converted to atmospheric CO_2.

For the purpose of international reporting, the IPCC (IPCC/UNEP/OECD/IEA 1997) requires that particular adjustments be made to national fuel consumption statistics. Certain fossil fuels can be manufactured into plastics, asphalt, lubricants, or other products. A portion of the carbon consumed for these non-energy products can be stored (i.e., sequestered) for long periods of time. To account for the fact that the carbon in these fuels ends up in products instead of being combusted (i.e., oxidized and released into the atmosphere), the fraction of fossil fuel-based carbon in manufactured products is subtracted from emission estimates. (See the Carbon Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter.) The fraction of this carbon stored in products that is eventually combusted in waste incinerators or combustion plants is accounted for in the Waste Chapter under Waste Combustion.

The IPCC (1997) also requires that CO_2 emissions from the consumption of fossil fuels for aviation and marine international transport activities (i.e., international bunker fuels) be reported separately, and not included in national emission totals. Estimates of carbon in products and international bunker fuel emissions for the United States are provided in Table 2-4 and Table 2-5.

End-Use Sector Consumption

When analyzing CO_2 emissions from fossil fuel combustion, four end-use sectors were defined: industrial, transportation, residential, and commercial.[6] Electric utilities also emit CO_2; however, these emissions occur as they combust fossil fuels to provide electricity to one of the four end-use sectors. For the discussion below, electric utility emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption. This method of distributing emissions assumes that each sector consumes electricity generated from an equally carbon-intensive mix of fuels and other energy sources. In reality, sources of electricity vary widely in carbon intensity (e.g., coal versus wind power). By giving equal carbon-intensity weight to each sector's electricity consumption, emissions attributed to one end-use sector may be somewhat overestimated, while emissions attributed to another end-use sector may be slightly underestimated. After the end-use sectors are discussed, emissions from electric utilities are

[6] See Glossary (Annex W) for more detailed definitions of the industrial, residential, commercial, and transportation end-use sector, as well as electric utilities.

Table 2-4: Fossil Fuel Carbon in Products (Tg CO_2 Eq.)*

Sector	1990	1995	1996	1997	1998	1999
Industrial	274.4	315.8	320.5	335.9	340.6	358.8
Transportation	1.2	1.2	1.1	1.2	1.2	1.2
Territories	0.6	1.0	1.5	1.6	1.5	1.7
Total	**276.2**	**317.9**	**323.1**	**338.6**	**343.4**	**361.7**

* See Carbon Stored in Products from Non-Energy Uses of Fossil Fuels section for additional detail.
Note: Totals may not sum due to independent rounding.

Table 2-5: CO_2 Emissions from International Bunker Fuels (Tg CO_2 Eq.)*

Vehicle Mode	1990	1995	1996	1997	1998	1999
Aviation	46.7	51.1	52.1	55.9	55.0	61.0
Marine	67.3	49.9	50.1	53.9	57.8	46.4
Total	**114.0**	**101.0**	**102.2**	**109.8**	**112.8**	**107.3**

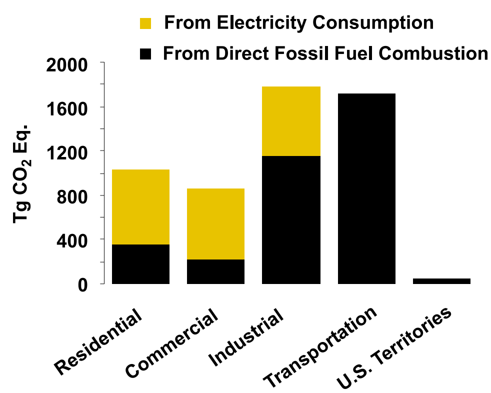
* See International Bunker Fuels section for additional detail.
Note: Totals may not sum due to independent rounding.

addressed separately. Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. Table 2-6 and Figure 2-10 summarize CO_2 emissions from direct fossil fuel combustion and pro-rated electric utility emissions from electricity consumption by end-use sector.

The electric power industry in the United States is currently undergoing significant changes. Both Federal and State government agencies are modifying regulations to create a competitive market for electricity generation from what was a market dominated by vertically integrated and regulated monopolies (i.e., electric utilities). These changes have led to the growth of nonutility power producers, including the sale of generating capacity by electric utilities to nonutilities.[7] As a result, the proportion of electricity in the United States generated by nonutilities has grown from about 8 percent in 1990 to 16 percent in 1999. Fuel consumption and emissions by nonutilities are currently allocated to the industrial end-use sector, separate from electric utilities, due to data limitations. Therefore, emissions associated with electricity generation in Table 2-6 are underestimated and emissions associated with direct fuel combustion by the industrial end-use sector are overestimated by an equal amount.

Figure 2-10

1999 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion



Note: All emissions related to the generation of electricity by nonutilities are currently allocated to the combustion category under the industrial sector due to data limitations.

Industrial End-Use Sector

The industrial end-use sector accounted for the largest share (33 percent) of CO_2 emissions from fossil fuel combustion. On average, 65 percent of these emissions resulted from the direct consumption of fossil fuels

[7] In 1999, 50,884 megawatts of electrical generating capacity was sold by electric utilities to nonutilities, or 6.4 percent of total electric power industry capacity.

Table 2-6: Fossil Fuel Carbon in Products and CO_2 Emissions from International Bunker Fuel Combustion (Tg CO_2 Eq.)

End-Use Sector	1990	1995	1996	1997	1998	1999
Industrial	**1,636.0**	**1,709.5**	**1,766.0**	**1,783.6**	**1,758.8**	**1,783.9**
Combustion[a]	1,023.5	1,101.0	1,140.6	1,141.1	1,113.3	1,155.6
Electricity[b]	612.6	608.5	625.4	642.5	645.5	628.3
Transportation	**1,474.4**	**1,581.8**	**1,621.2**	**1,631.4**	**1,659.0**	**1,716.4**
Combustion	1,471.8	1,579.4	1,618.8	1,628.9	1,656.5	1,714.0
Electricity[b]	2.6	2.4	2.4	2.5	2.5	2.4
Residential	**930.7**	**988.7**	**1,047.5**	**1,044.2**	**1,040.9**	**1,035.8**
Combustion	332.1	362.3	390.4	374.9	341.0	354.1
Electricity[b]	598.6	626.4	657.0	669.3	699.9	681.6
Commercial	**760.8**	**797.2**	**828.2**	**872.9**	**880.2**	**864.0**
Combustion	217.3	223.9	232.8	233.7	217.4	223.0
Electricity[b]	543.6	573.3	595.4	639.2	662.8	641.0
U.S. Territories	**33.7**	**44.0**	**40.1**	**42.8**	**47.9**	**53.0**
Total	**4,835.7**	**5,121.3**	**5,303.0**	**5,374.9**	**5,386.8**	**5,453.1**

[a] Includes emissions related to the generation of electricity by nonutility power producers.
[b] Does not include emissions related to the consumption of electricity generated by nonutilities—versus regulated electric utilities. All emissions related to the generation of electricity by nonutilities are currently allocated to the combustion category under the industrial sector due to data limitations.
Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electric utilities are allocated based on aggregate national electricity consumption by each end-use sector.

in order to meet industrial energy demands such as for steam and process heat. The remaining 35 percent was associated with their consumption of electricity for uses such as motors, electric furnaces, ovens, and lighting.[8]

The industrial end-use sector includes activities such as manufacturing, construction, mining, and agriculture.[9] The largest of these activities in terms of energy consumption is manufacturing, which was estimated in 1994 to have accounted for about 80 percent of industrial energy consumption (EIA 1997). Manufacturing energy consumption was dominated by several industries—petroleum products, chemical products, primary metals, paper and products, foods; and stone, clay, and glass products—which combined accounted for about 84 percent (i.e., roughly two-thirds of the entire industrial end-use sector in 1994).

In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output; however, certain activities within the sector, such as heating of industrial buildings and agricultural energy consumption, are also affected by weather conditions.[10] In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy intensive manufacturing products to less energy intensive products (e.g., from steel to computer equipment) also have a significant affect on industrial emissions.

From 1998 to 1999, total industrial production and manufacturing output were reported to have increased by 4.2 and 4.8 percent, respectively (FRB 2000). However, excluding the fast growing computer, communication equipment, and semiconductor industries from these indexes reduces their growth considerably—to 1.2 and 1.5 percent, respectively—and illustrates some of the structural changes occurring in the U.S. economy (see Figure 2-11).

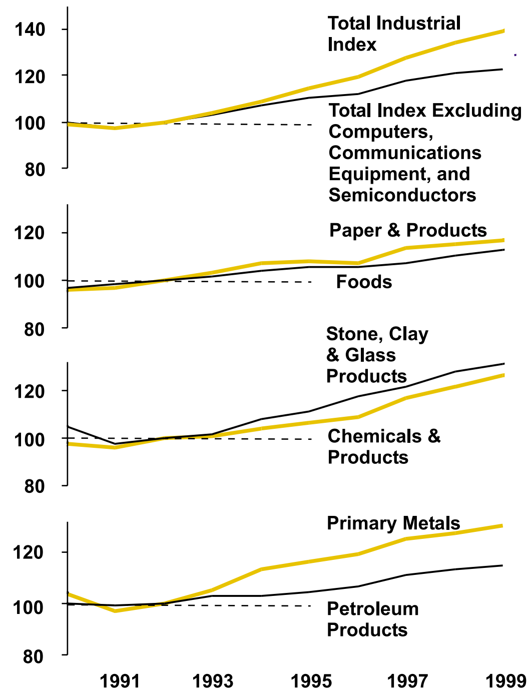
[8] This fraction only includes emissions from electric utilities, and therefore likely underestimates electricity associated emissions because it excludes CO_2 emissions associated with electricity generated by nonutility power producers. These nonutility power producers, however, are included in the direct fuel combustion category of the industrial end-use sector. Therefore, because of the inclusion of nonutilities and the fact that some industrial facilities generate their own electricity without obtaining it from electric utilities, the fraction of the industrial end-use sector's emissions associated with meeting actual steam and process heat demands is likely overestimated since a portion of that fuel is actually used to generate electricity (e.g., cogeneration).

[9] See Glossary (Annex W) for a more detailed definition of the industrial end-use sector.

[10] Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

Figure 2-11

Industrial Production Indexes (Index 1992=100)



According to current EIA sectoral definitions, the industrial sector also includes emissions from nonutility generators (e.g., independent power producers) who produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market.[11] The number of nonutility generators and the quantity of electricity they produce has increased significantly as many States have begun opening their electricity markets to competition. In future inventories, these nonutility generators will be removed from the industrial sector and incorporated into a single electric power sector with electric utilities.

Despite the growth in industrial output (49 percent) and the overall U.S. economy (32 percent) from 1990 to 1999, emissions from the industrial end-use sector increased by only 9.0 percent, which is less that all other end-use sectors in percentage terms. For example, in 1998 emissions decreased by 1.4 percent and then in 1999 increased by the same percentage. The reasons for the disparity between rapid growth in industrial output and stagnant growth in industrial emissions are not entirely clear. It is likely, though, that several factors have influenced industrial emission trends, including: 1) a mild winter in 1998 and 1999, leading to lower than normal energy consumption in industries affected by the weather; 2) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries; 3) improvements in energy efficiency; and 4) a lowering of the carbon intensity of fossil fuel consumption as industry shifts from its historical reliance on coal and coke to heavier usage of natural gas. Assessments of industrial end-use sector trends, however, are complicated by the growth of nonutility generation and emissions.[12]

Industry was the largest user of fossil fuels for non-energy applications. Fossil fuels can be used for producing products such as fertilizers, plastics, asphalt, or lubricants that can sequester or store carbon for long periods of time. Asphalt used in road construction, for example, stores carbon essentially indefinitely. Similarly, fossil fuels used in the manufacture of materials like plastics can also store carbon, if the material is not burned. The amount of carbon contained in industrial products made from fossil fuels rose 31 percent between 1990 and 1999, to 361.7 Tg CO_2 Eq.[13]

Transportation End-Use Sector

Transportation was second to the industrial end-use sector in terms of U.S. CO_2 emissions from fossil fuel combustion, accounting for slightly over 31 percent—excluding international bunker fuels. Almost all of the energy consumed in this end-use sector came from petroleum-based products, with nearly two-thirds due to gasoline consumption in automobiles and other highway

[11] Nonutility generators also include cogenerators, who produce both useful process heat and electricity. See Glossary (Annex W) for a more detailed definition.

[12] The opening of the electric power industry to competition may have also led to some data collection problems as electric utility assets are transferred and government reporting requirements are revised. These reporting problems are expected to be corrected, however, in future inventories.

[13] See the Carbon Stored in Products in Non-Energy Uses of Fossil Fuels for a more detailed discussion. Also, see Waste Combustion in the Waste chapter for a discussion of emissions from the incineration or combustion of fossil fuel-based products.

vehicles. Other fuel uses, especially diesel fuel for the trucking industry and jet fuel for aircraft, accounted for the remainder.[14]

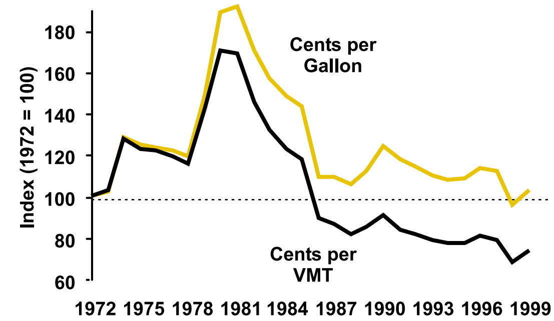
Carbon dioxide emissions from fossil fuel combustion for transportation increased by 16 percent from 1990 to 1999, to 1,716.4 Tg CO_2 Eq. The growth in transportation end-use sector emissions has been relatively steady, including a 3.5 percent single year increase in 1999. Demand for transportation fuels has been driven by several factors, including but not limited to: 1) increased activity in almost all modes of travel; 2) relatively low transportation fuel prices through 1999; and 3) stagnant vehicle fuel efficiency.

Since 1990, travel activity in the United States has grown more rapidly than population, with a 14 percent increase in vehicle miles traveled per capita and a 9 percent increase in per capita jet fuel consumption by U.S. commercial air carriers. Motor gasoline and other petroleum product prices during the 1990s generally declined, reaching historic lows in 1998 and only partially rebounding in 1999 (see Figure 2-12). Improvements in the average fuel efficiency for the U.S. vehicle fleet stagnated in the 1990s after increasing steadily since 1977 (EIA 2000a). The average miles per gallon achieved by the fleet actually decreased by slightly less than one percent in both 1998 and 1999. This trend was due, in part, to the increasing dominance of new motor vehicle sales by less fuel-efficient light-duty trucks and sport-utility vehicles (see Figure 2-13).

Table 2-7 below provides a detailed breakdown of CO_2 emissions by fuel category and vehicle type for the transportation end-use sector. Fifty-seven percent of the emissions from this end-use sector were the result of the combustion of motor gasoline in passenger cars and light-duty trucks. Diesel highway vehicles and jet aircraft were also significant contributors, accounting for 15 and 13 percent of CO_2 emissions from the transportation end-use sector, respectively.

Figure 2-12

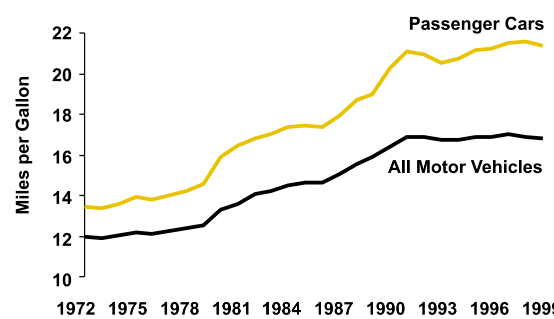
Motor Gasoline Retail Prices (Real)



Source for gasoline prices: DOE/EIA-0384(99), Annual Energy Review 1999, July, 2000, Table 5.22
Source for motor vehicle fuel efficiency: DOT/FHWA, Highway Statistics Summary to 1995, Highway Statistic 1996, 1997, 1998, 1999.

Figure 2-13

Motor Vehicle Fuel Efficiency



Source: DOT/FHWA, Highway Statistics Summary to 1995, Highway Statistics 1996, Highway Statistics 1997, 1998, 1999.

Residential and Commercial End-Use Sectors

The residential and commercial end-use sectors accounted for an average 19 and 16 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing to about 74 and 66 percent of emissions from the commercial and residential end-use sectors, respectively.[15] The remaining emissions were largely due to the

[14] See Glossary (Annex W) for a more detailed definition of the transportation end-use sector.

[15] These fractions only include emissions from electric utilities, and therefore likely underestimate electricity associated emissions because they exclude CO_2 emissions associated with electricity generated by nonutility power producers, which are currently allocated to the direct fuel combustion category under the industrial end-use sector.

Table 2-7: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.)

Fuel/Vehicle Type	1990		1995	1996	1997	1998	1999
Motor Gasoline	**955.5**		**1,023.0**	**1,041.4**	**1,050.6**	**1,074.0**	**1,096.6**
Passenger Cars	612.8		634.3	646.6	652.3	666.8	680.9
Light-Duty Trucks	274.1		314.2	320.4	323.1	342.4	349.6
Other Trucks	41.4		40.0	40.7	40.5	32.1	32.8
Motorcycles	1.6		1.7	1.7	1.7	1.7	1.8
Buses	2.0		3.0	2.1	2.2	0.8	0.9
Construction Equipment	2.2		2.4	2.4	2.5	2.0	2.0
Agricultural Machinery	4.4		7.9	7.8	8.2	7.6	7.8
Boats (Recreational)	16.9		19.5	19.7	20.1	20.5	21.0
Distillate Fuel Oil (Diesel)	**277.4**		**312.2**	**329.0**	**342.8**	**353.5**	**367.1**
Passenger Cars	7.1		7.6	7.6	7.9	7.6	8.0
Light-Duty Trucks	9.0		11.2	13.1	14.2	14.4	15.1
Other Trucks	164.1		195.4	207.0	216.1	225.5	236.5
Buses	7.9		9.9	8.6	9.2	10.7	11.2
Construction Equipment	10.5		10.5	10.9	11.2	10.8	11.3
Agricultural Machinery	23.1		23.0	23.8	24.5	23.7	24.9
Boats (Freight)	18.0		16.1	18.4	18.3	17.8	18.7
Locomotives	26.3		29.5	31.5	32.4	31.6	33.2
Marine Bunkers	11.4		9.1	8.2	9.0	11.4	8.2
Jet Fuel	**220.4**		**219.9**	**229.8**	**232.1**	**235.6**	**242.9**
General Aviation	6.3		5.3	5.8	6.1	7.7	8.4
Commercial Air Carriers	118.2		121.4	124.9	129.4	131.4	137.3
Military Vehicles	36.1		21.6	20.1	17.8	18.4	17.1
Aviation Bunkers	46.7		51.1	52.1	55.9	55.0	61.0
Other[a]	13.1		20.5	26.8	23.0	23.0	19.2
Aviation Gasoline	**3.1**		**2.7**	**2.6**	**2.7**	**2.4**	**2.7**
General Aviation	3.1		2.7	2.6	2.7	2.4	2.7
Residual Fuel Oil	**80.4**		**72.1**	**67.5**	**56.7**	**55.9**	**64.1**
Boats (Freight)[b]	24.5		31.3	25.7	11.8	9.5	25.9
Marine Bunkers[b]	55.8		40.8	41.8	44.9	46.4	38.2
Natural Gas	**36.0**		**38.3**	**38.9**	**41.5**	**34.9**	**34.8**
Passenger Cars	+		0.1	+	+	+	+
Light-Duty Trucks	+		+	+	+	+	+
Buses	+		0.1	0.1	0.2	0.2	0.2
Pipeline	36.0		38.2	38.8	41.3	34.7	34.6
LPG	**1.3**		**1.0**	**0.9**	**0.8**	**0.9**	**1.0**
Light-Duty Trucks	+		+	+	+	+	+
Other Trucks	0.5		0.5	0.4	0.4	0.3	0.4
Buses	0.8		0.5	0.5	0.4	0.5	0.6
Electricity	**2.6**		**2.4**	**2.4**	**2.5**	**2.5**	**2.4**
Buses	+		+	+	+	+	+
Locomotives	2.1		1.9	1.9	1.9	2.0	1.9
Pipeline	0.5		0.5	0.5	0.6	0.5	0.5
Lubricants	11.7		11.2	10.9	11.5	12.0	12.1
Total (Including Bunkers)[c]	**1,588.4**		**1,682.8**	**1,723.4**	**1,741.2**	**1,771.7**	**1,823.7**
Total (Excluding Bunkers)[c]	**1,474.4**		**1,581.8**	**1,621.2**	**1,631.4**	**1,659.0**	**1,716.4**

Note: Totals may not sum due to independent rounding.

[a] Including but not limited to fuel blended with heating oils and fuel used for chartered aircraft flights.

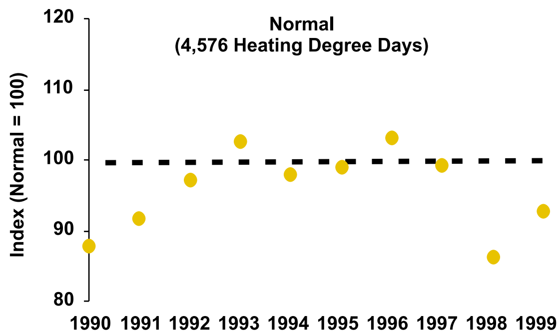
[b] Fluctuations in emission estimates from the combustion of residual fuel oil are currently unexplained, but may be related to data collection problems.

[c] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.

+ Does not exceed 0.05 Tg of CO_2 Eq.

Figure 2-14

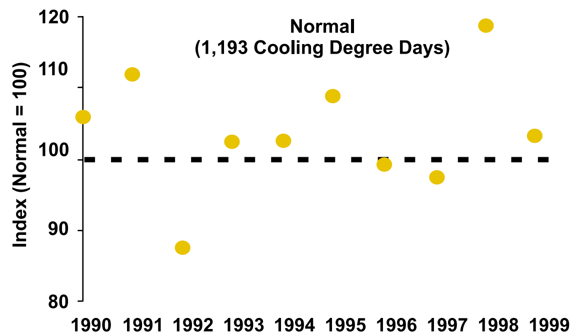
Heating Degree Days[16]



Note: Excludes Alaska and Hawaii
Source: DOE/EIA-0384(99), Annual Energy Review 1999, July, 2000, Table 1.7 and 1.8.

Figure 2-15

Cooling Degree Days[17]



Note: Excludes Alaska and Hawaii
Source: DOE/EIA-0384(99), Annual Energy Review 1999, July 2000, Table 1.7 and 1.8.

direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both these end-use sectors.

Emissions from residences and commercial buildings generally increased throughout the 1990s, and, unlike in other end-use sectors, emissions in these sectors did not decline during the economic downturn in 1991 (see Table 2-6). This difference exists because short-term fluctuations in energy consumption in these sectors are affected proportionately more by the weather than by prevailing economic conditions. In the long-term, both end-use sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

In 1999, winter conditions in the United States were warmer than normal (i.e., heating degree days were 7 percent below normal), although not nearly as warm as in 1998 (see Figure 2-14). Due, in part, to this slight cooling relative to the previous year, emissions from natural gas consumption in residences and commercial establishments increased by 3 percent and 2 percent, respectively.

In 1999, electricity sales by electric utilities to the residential and commercial end-use sectors increased by 1.0 and 0.2 percent, respectively, as compared to the previous year. Cooler summer conditions in 1999 relative to 1998, although still warmer than normal, helped to moderate growth in air conditioning driven electricity consumption (see Figure 2-15). Historically, the change in energy demand associated with a change in heating degree days has been greater than an equivalent change in cooling degree days. These temperature trends—along with other trends such as overall population growth—led to a 0.5 and 1.8 percent decrease in residential and commercial end-use sector emissions from 1998 to 1999, respectively.

Electric Utilities

The United States relies on electricity to meet a significant portion of its energy requirements. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for uses such as lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 2-16).

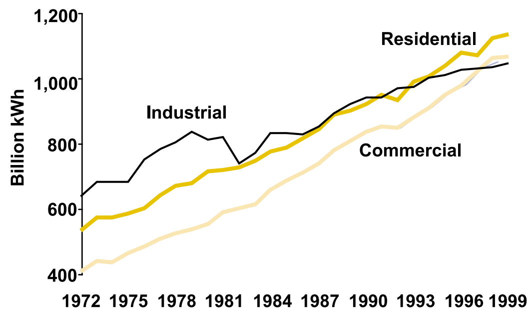
It is important to note that the electric utility sector includes only regulated utilities. According to current EIA sectoral definitions, nonutility generators of electricity (e.g., independent power producers, qualifying cogenerators, and other small power producers) are included in the industrial end-use sector. These nonutility

[16] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1961 through 1990.

[17] Degree days are relative measurements of outdoor air temperature. Cooling degree days are deviations of the mean daily temperature above 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1961 through 1990.

Figure 2-16

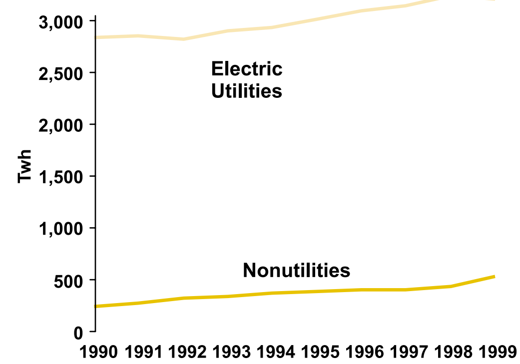
Electric Utility Retail Sales by End-Use Sector



Note: The transportation end-use sector consumes minor quanties of electricty.

Figure 2-17

Net Generation by Electric Utilities and Nonutilities



Source: EIA (2000c)

generators produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to retail customers). The number of nonutility generators and quantity of electricity they produce has increased significantly as many States have begun opening their electricity markets for generation to competition (see Figure 2-17).

The Energy Information Agency has estimated emissions from the entire electric power industry, including regulated utilities and nonutilities was roughly 41 percent of U.S. CO_2 emissions from fossil fuel combustion versus 36 percent from utilities alone (EIA 2000c). As U.S. energy statistics are revised to account for the changes occurring in the electric power industry, these nonutility generators will be removed from the industrial end-use sector and incorporated into a single sector with electric utilities.[18]

In 1999, CO_2 emissions from electric utilities decreased by 2.9 percent relative to the previous year despite increased electricity consumption and the robust growth in the U.S. economy. A large part of this decrease can be attributed to the sale of approximately 7 percent of electric utility generating capacity to nonutility power producers in 1999.[19] In addition, the summer of 1999 for the United States, although slightly warmer than usual, was cooler than the pervious year's summer, with cooling degree days down by 13 percent (see Figure 2-15). A third factor leading to the decline in utility emissions was the increased output from nuclear plants, which offset the need for additional fossil fuel consumption. Net generation of electricity by nuclear plants increased by 8 percent from 1998 to 1999, reaching record levels along with plant capacity factors (i.e., utilization).[20]

To generate the majority of their electricity, utilities combusted fossil fuels, especially coal. The combustion of fossil fuels accounts for the majority (68 percent) of the electricity generated by utilities in the United States (EIA 2000a). Electric utilities rely on more carbon intensive coal for a majority of their primary energy; however, they also employ many low or near zero carbon emitting technologies such as nuclear, hydro, and wind.

Electric utilities were the dominant consumer of coal in the United States, accounting for 85 percent in 1999. Consequently, changes in electricity demand have a significant impact on coal consumption and associated U.S. CO_2 emissions. Coal consumption by utilities in 1999 decreased by 2 percent (343 Tbtu) in 1999, primarily due to the sale of generating capacity to nonutility power producers. This decrease, therefore, was offset by an 11 percent (314 Tbtu) increase in coal consumption by in industrial end-use sector (i.e., only the sector in which the emissions were accounted for actually changed).

[18] It is important to note, though, that much of the electricity generated by nonutility power producers is sold to utilities for resale to retail customers, and therefore is included in electric utility sales statistics.

[19] Gross generation of electricity by nonutilities increased by about 35 percent from 1998 to 1999.

[20] Electricity output from hydroelectric dams was relatively constant, decreasing by 0.6 percent between 1998 and 1999.

Box 2-2: Sectoral Carbon Intensity Trends Related to Fossil Fuel and Overall Energy Consumption

Fossil fuels are the predominant source of energy in the United States, and carbon dioxide (CO_2) is emitted as a product from their complete combustion. Useful energy, however, can be generated from many other sources that do not emit CO_2 in the energy conversion process. In the United States, useful energy is also produced from renewable (i.e., hydropower, biofuels, geothermal, solar, and wind) and nuclear sources.[21]

Energy-related CO_2 emissions can be reduced by not only lowering total energy consumption (e.g., through conservation measures) but also by lowering the carbon intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of carbon emitted—in the form of CO_2—from the combustion of fossil fuels is dependent upon the carbon content of the fuel and the fraction of that carbon that is oxidized.[22] Fossil fuels vary in their average carbon content, ranging from about 53 Tg CO_2 Eq./EJ for natural gas to upwards of 95 Tg CO_2 Eq./EJ for coal and petroleum coke.[23] In general, the carbon intensity per unit of energy of fossil fuels is the highest for coal products, followed by petroleum and then natural gas. Other sources of energy, however, may be directly or indirectly carbon neutral (i.e., 0 Tg CO_2 Eq./EJ). Energy generated from nuclear and many renewable sources do not result in direct emissions of CO_2. Biofuels such as wood and ethanol are also considered to be carbon neutral, as the CO_2 emitted during their combustion is assumed to be offset by the carbon sequestered in the growth of new biomass.[24] The overall carbon intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 2-8 provides a time series of the carbon intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the carbon intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting or wood for heat. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest carbon intensity, which was related to the large percentage of energy derived from natural gas for heating. The carbon intensity of the commercial sector was greater than the residential sector for the period from 1990 to 1996, but then declined to a comparable level as commercial businesses shifted away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher carbon intensities over this period. The carbon intensity of the transportation sector was closely related to the carbon content of petroleum products (e.g., motor gasoline and jet fuel, both around 67 Tg CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electric utility sector had the highest carbon intensity due to its heavy reliance on coal for generating electricity.

Table 2-8: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./EJ)

Sector	1990		1995	1996	1997	1998	1999
Residential[a]	53.8		53.7	53.6	53.7	53.6	53.6
Commercial[a]	55.7		54.2	54.2	54.0	53.8	53.9
Industrial[a]	65.1		64.2	63.9	64.0	64.6	65.4
Transportation[a]	67.3		67.1	67.0	67.0	67.1	67.1
Electric Utilities[b]	82.0		82.1	83.1	82.9	82.3	82.5
All Sectors[c]	**69.4**		**68.9**	**69.0**	**69.1**	**69.5**	**69.5**

[a] Does not include electricity or renewable energy consumption.
[b] Does not include electricity produced using nuclear or renewable energy.
[c] Does not include nuclear or renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption. Exajoule (EJ) = 10^{18} joules = 0.9479 QBtu.

---

[21] Small quantities of CO_2, however, are released from some geologic formations tapped for geothermal energy. These emissions are included with fossil fuel combustion emissions from the electric utilities. Carbon dioxide emissions may also be generated from upstream activities (e.g., manufacture of the equipment) associated with fossil fuel and renewable energy activities, but are not accounted for here.

[22] Generally, 97 to 99.5 percent of the carbon in fossil fuel is oxidized to CO_2 with most carbon combustion technologies used in the United States.

[23] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

[24] This statement assumes that there is no net loss of biomass-based carbon associated with the land use practices used to produce these biomass fuels.

In contrast to Table 2-8, Table 2-9 presents carbon intensity values that incorporate energy consumed from all sources (i.e., fossil fuels, renewables, and nuclear). In addition, the emissions related to the generation of electricity have been attributed to both electric utilities and the end-use sector in which that electricity was eventually consumed.[25] This Table, therefore, provides a more complete picture of the actual carbon intensity of each end-use sector per unit of energy consumed. The transportation end-use sector in Table 2-9 emerges as the most carbon intensive when all sources of energy are included, due to its almost complete reliance on petroleum products and relatively minor amount of biomass based fuels such as ethanol. The "other end-use sectors" (i.e., residential, commercial, and industrial) use significant quantities of biofuels such as wood, thereby lowering the overall carbon intensity. The carbon intensity of electric utilities differs greatly from the scenario in Table 2-8, where only the energy consumed from the direct combustion of fossil fuels was included. This difference is due almost entirely to the inclusion of electricity generation from nuclear and hydropower sources, which do not emit carbon dioxide.

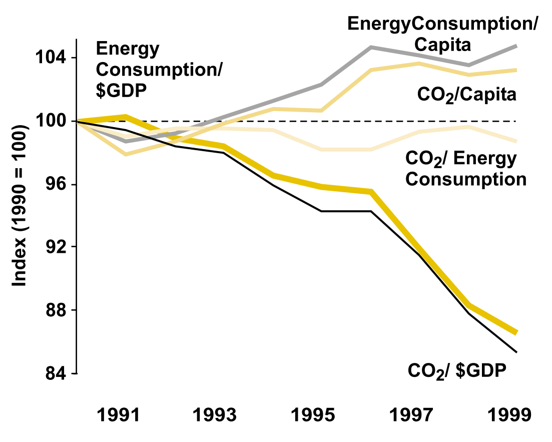
By comparing the values in Table 2-8 and Table 2-9, a couple of observations can be made. The usage of renewable and nuclear energy sources has resulted in a significantly lower carbon intensity of the U.S. economy. However, over the ten year period of 1990 through 1999, the carbon intensity of U.S. fossil fuel consumption has been fairly constant, as the proportion of renewable and nuclear energy technologies has not changed significantly.

Although the carbon intensity of total energy consumption has remained fairly constant, per capita energy consumption has increased leading to a greater energy-related CO_2 emissions per person in the United States since 1990 (see Figure 2-18). Because of the strong growth in the U.S. economy, though, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) declined in the 1990s.

Figure 2-19 and Table 2-10 present the detailed CO_2 emission trends underlying the carbon intensity differences and changes described in Table 2-8. In Figure 2-19, changes over time in both overall end-use sector-related emissions and electricity-related emissions for each year since 1990 are highlighted. In Table 2-10 changes in emissions since 1990 are presented by sector and fuel type to provide a more detailed accounting.

Figure 2-18

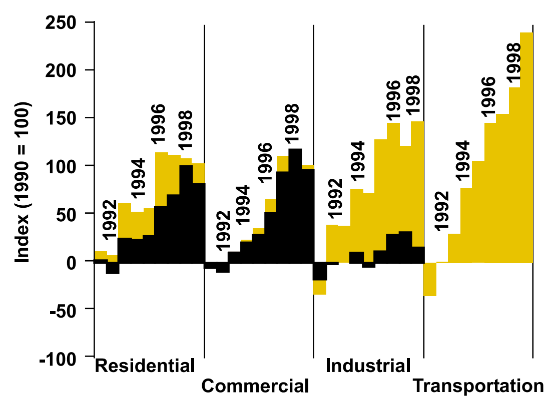
U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP



Source: BEA (2000), Census (2000), Emission and energy consumption estimate, in this report.

Figure 2-19

Change in CO_2 Emissions from Fossil Fuel Combustion Since 1990 by End-Use Sector



Dark shaded columns relate to changes in emissions from electricity consumption. Lightly shaded columns relate to changes in emissions from both electricity and direct fossil fuel combustion.

[25] In other words, the emissions from the generation of electricity are intentionally double counted by attributing them both to utilities and the end-use sector in which electricity consumption occurred.

Table 2-9: Carbon Intensity from Energy Consumption by Sector (Tg CO_2 Eq./EJ)

Sector	1990	1995	1996	1997	1998	1999
Transportation[a]	67.0	66.8	66.8	66.7	66.8	66.8
Other End-Use Sectors[a,b]	54.5	53.1	53.2	54.0	54.1	53.2
Electric Utilities[c]	56.0	54.4	54.8	56.3	56.3	55.2
All Sectors[d]	**58.6**	**57.5**	**57.6**	**58.2**	**58.4**	**57.9**

[a] Includes electricity (from fossil fuel, nuclear, and renewable sources) and direct renewable energy consumption.
[b] Other End-Use Sectors include the residential, commercial, and industrial sectors.
[c] Includes electricity generation from nuclear and renewable sources.
[d] Includes nuclear and renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption. Exajoule (EJ) = 10^{18} joules = 0.9479 QBtu.

Table 2-10: Change in CO_2 Emissions from Direct Fossil Fuel Combustion Since 1990 (Tg CO_2 Eq.)

Sector/Fuel Type	1991	1995	1996	1997	1998	1999
Residential	**9.9**	**30.2**	**58.3**	**42.8**	**8.9**	**22.0**
Coal	(0.5)	(0.8)	(0.7)	(0.4)	(1.6)	(1.6)
Natural Gas	8.8	24.6	46.0	32.0	8.0	16.4
Petroleum	1.7	6.4	13.0	11.2	2.6	7.3
Commercial	**1.5**	**6.6**	**15.5**	**16.4**	**0.1**	**5.7**
Coal	(0.8)	(1.2)	(1.0)	(0.5)	(2.5)	(2.5)
Natural Gas	5.8	22.1	29.2	32.3	21.1	24.0
Petroleum	(3.5)	(14.3)	(12.6)	(15.3)	(18.5)	(15.8)
Industrial	**(15.8)**	**77.6**	**117.1**	**117.7**	**89.8**	**132.1**
Coal	1.6	15.2	8.0	9.9	8.8	38.1
Natural Gas	6.8	82.4	100.2	99.7	85.2	86.8
Petroleum	(24.2)	(20.1)	8.9	8.1	(4.2)	7.3
Transportation	**(34.1)**	**107.6**	**147.0**	**157.1**	**184.7**	**242.2**
Coal	NE	NE	NE	NE	NE	NE
Natural Gas	(3.2)	2.3	2.9	5.5	(1.1)	(1.2)
Petroleum	(30.9)	105.3	144.1	151.7	185.8	243.4
Electric Utilities	**(20.4)**	**53.2**	**122.9**	**196.2**	**253.3**	**196.0**
Coal	(14.3)	78.5	168.4	220.4	234.7	202.7
Natural Gas	(0.4)	20.7	(4.6)	8.5	24.7	16.9
Petroleum	(5.7)	(45.9)	(40.8)	(32.7)	(6.0)	(23.4)
Geothermal	+	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)
U.S. Territories	**5.6**	**10.3**	**6.4**	**9.1**	**14.2**	**19.3**
Coal	0.1	0.3	0.3	0.3	0.3	0.3
Natural Gas	NE	NE	NE	NE	NE	NE
Petroleum	5.5	10.0	6.1	8.8	14.0	19.0
All Sectors	**(53.3)**	**285.6**	**467.3**	**539.2**	**551.1**	**617.4**

+ Does not exceed 0.05 Tg CO_2 Eq.
NE (Not Estimated)
*Includes nonutility electricity generators.
Note: Totals may not sum due to independent rounding.

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). A detailed description of the U.S. methodology is presented in Annex A, and is characterized by the following steps:

1. *Determine fuel consumption by fuel type and sector.* By aggregating consumption data by sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal,

petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.), estimates of total U.S. fossil fuel consumption for a particular year were made. The United States does not include territories in its national energy statistics; therefore, fuel consumption data for territories was collected separately. [26]

2. *Determine the total carbon content of fuels consumed.* Total carbon was estimated by multiplying the amount of fuel consumed by the amount of carbon in each fuel. This total carbon estimate defines the maximum amount of carbon that could potentially be released to the atmosphere if all of the carbon in each fuel were converted to CO_2. The carbon content coefficients used by the United States are presented in Annex A.

3. *Subtract the amount of carbon stored in products.* Non-energy uses of fossil fuels can result in storage of some or all of the carbon contained in the fuel for some period of time, depending on the end-use. For example, asphalt made from petroleum can sequester up to 100 percent of the carbon for extended periods of time, while other fossil fuel products, such as lubricants or plastics, lose or emit some carbon when they are used and/or burned as waste. Aggregate U.S. energy statistics include consumption of fossil fuels for non-energy uses; therefore, the portion of carbon that remains in products after they are manufactured was subtracted from potential carbon emission estimates.[27] The amount of carbon remaining in products was based on the best available data on the end-uses and fossil fuel products. These non-energy uses occurred in the industrial and transportation sectors and U.S. territories. Emission of CO_2 associated with the disposal of these fossil fuel-based products are not accounted for here, but are instead accounted for under the Waste Combustion section in the Waste chapter.

4. *Adjust for carbon that does not oxidize during combustion.* Because combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted to the atmosphere. Rather, it remains behind as soot and ash. The estimated amount of carbon not oxidized due to inefficiencies during the combustion process was assumed to be 1 percent for petroleum and coal and 0.5 percent for natural gas (see Annex A).

5. *Subtract emissions from international bunker fuels.* According to the IPCC guidelines (IPCC/UNEP/OECD/IEA 1997) emissions from international transport activities, or bunker fuels, should not be included in national totals. Because U.S. energy consumption statistics include these bunker fuels—distillate fuel oil, residual fuel oil, and jet fuel—as part of consumption by the transportation end-use sector, emissions from international transport activities were calculated separately and subtracted from emission estimates for the transportation end-use sector. The calculations for emissions from bunker fuels follow the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, determination of carbon content, and adjustment for the fraction of carbon not oxidized).[28]

6. *Allocate transportation emissions by vehicle type.* Because the transportation end-use sector was the largest direct consumer of fossil fuels in the United States,[29] a more detailed accounting of carbon dioxide emissions is provided. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Specific data by vehicle type were not available for 1999; therefore, the 1998 percentage allocations were applied to 1999 fuel consumption data in order to estimate emissions in 1999. Military vehicle jet fuel consumption was provided by the Defense Energy Support Center, under Department of Defense's (DoD) Defense Logistics Agency and the Office of the Undersecretary of Defense (Environmental Security). The difference between total U.S. jet fuel consumption (as reported by DOE/EIA) and civilian air carrier consumption for both domestic and international flights (as reported by DOT/BTS and BEA) plus

[26] Fuel consumption by U.S. territories (i.e. American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of 53 Tg of CO_2 Eq. in 1999.

[27] See Carbon Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter for a more detailed discussion.

[28] See International Bunker Fuels section in this chapter for a more detailed discussion.

[29] Electric utilities are not considered a final end-use sector, because they consume energy solely to provide electricity to the other sectors.

military jet fuel consumption is reported as "other" under the jet fuel category in Table 2-7, and includes such fuel uses as blending with heating oils and fuel used for chartered aircraft flights.

Data Sources

Data on fuel consumption for the United States and its territories, and carbon content of fuels were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). Fuel consumption data were obtained primarily from the *Annual Energy Review* (EIA 2000a) and various EIA databases. Data on military jet fuel use was supplied by the Office of the Under Secretary of Defense (Environmental Security) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD). Estimates of international bunker fuel emissions are discussed in the section entitled International Bunker Fuels. Estimates of carbon stored in products are discussed in the section entitled Carbon Stored in Products from Nonfuel Uses of Fossil Fuels.

IPCC (IPCC/UNEP/OECD/IEA 1997) provided fraction oxidized values for petroleum and natural gas. Bechtel (1993) provided the fraction oxidation values for coal. Vehicle type fuel consumption data for the allocation of transportation end-use sector emissions were primarily taken from the *Transportation Energy Databook* prepared by the Center for Transportation Analysis at Oak Ridge National Laboratory (DOE 1993, 1994, 1995, 1996, 1997, 1998, 1999). Specific data on military fuel consumption were taken from DESC (2000). Densities for each military jet fuel type were obtained from the Air Force (1998).

Carbon intensity estimates were developed using nuclear and renewable energy data from EIA (2000a) and fossil fuel consumption data as discussed above and presented in Annex A.

For consistency of reporting, the IPCC has recommended that national inventories report energy data—and emissions from energy—using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA, and used in this inventory, are, instead, "bottom up" in nature. In other words, they are collected through surveys at the point of delivery or use and aggregated to determine national totals.[30]

It is also important to note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standard, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[31]

Uncertainty

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted, in principle is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

There are uncertainties, however, in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., petroleum), the amount of carbon contained in the fuel per unit of useful energy can vary.

Although statistics of total fossil fuel and other energy consumption are considered to be relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) are considerably more uncertain. For example, for some fuels the sectoral allocations are based

[30] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex R for a comparison of U.S. estimates using top-down and bottom-up approaches.

[31] A crude convention to convert between gross and net calorific values is to reduce the heat content of solid and liquid fossil fuels by 5 percent and gaseous fuels by 10 percent to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics are generally presented using net calorific values.

on price rates (i.e., tariffs). However, commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the more recent deregulation of the electric power industry have likely led to problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

Non-energy uses of the fuel can also create situations where the carbon is not emitted to the atmosphere (e.g., plastics, asphalt, etc.) or is emitted at a delayed rate. The proportions of fuels used in these non-energy production processes that result in the sequestration of carbon have been assumed. Additionally, inefficiencies in the combustion process, which can result in ash or soot remaining unoxidized for long periods, were also assumed. These factors all contribute to the uncertainty in the CO_2 estimates. More detailed discussions on the uncertainties associated with Carbon Stored in Products from Non-Energy Uses of Fossil Fuels and with International Bunker Fuels are provided under those sections in this chapter.

Other sources of uncertainty are fuel consumption by U.S. territories. The United States does not collect energy statistics for its territories at the same level of detail as for the fifty States and the District of Columbia. Therefore estimating both emissions and bunker fuel consumption by these territories is difficult.

For Table 2-7, uncertainties also exist as to the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to better allocate detailed transportation end-use sector emissions. In particular, fuel consumption data for marine vehicles are highly uncertain, as shown by the large fluctuations in emissions.

For the United States, however, these uncertainties impact on overall CO_2 emission estimates are believed to be relatively small. For the United States, CO_2 emission estimates from fossil fuel combustion are considered accurate within several percent. See, for example, Marland and Pippin (1990).

Carbon Stored in Products from Non-Energy Uses of Fossil Fuels

Besides being combusted for energy, fossil fuels are also consumed for non-energy end uses. The types of fuels used for non-energy uses are listed in Table 2-11. The fuels are used in the industrial and transportation end-use sectors and are quite diverse, including natural gas, asphalt, a viscous liquid mixture of heavy crude oil distillates, and coking coal. The non-energy fuel uses are equally diverse, and include application as solvents, reduction agents in metals production, lubricants, and waxes, or as raw materials in the manufacture of plastics, rubber, synthetic fibers, and fertilizers.

Carbon dioxide emissions arise from non-energy uses via multiple pathways. Emissions may occur directly from the fuel's consumption, as is the case with coking coal used in iron blast furnaces. Emissions may also occur during the manufacture of a product, as is the case in producing plastics or rubber from feedstocks. Additionally, in the case of solvents or lubricants, for example, emissions may occur during the (fuel-derived) product's lifetime. Overall, more than 75 percent of the total carbon consumed for non-energy end uses is stored in products, and not released to the atmosphere. However, some of the products release CO_2 at the end of their commercial life when they are disposed. These emissions are covered in the Waste chapter under Waste Combustion.

In 1999, fossil fuel consumption for non-energy uses constituted 8 percent (6,886 TBtu) of overall fossil fuel consumption, an increase from 1990, when it accounted for 7 percent of total consumption. In 1999, the carbon in non-energy fuel consumption was approximately 478 Tg CO_2 Eq., an increase of 34 percent since 1990. Nearly 362 Tg CO_2 Eq. of this carbon was stored, while the remaining 117 Tg CO_2 Eq. was emitted. Since 1990, the proportion of carbon emitted has grown slightly from 23 percent to 24 percent of total non-energy consumption. Table 2-12 shows the fate of the non-energy fossil fuel carbon for 1990 and 1995 through 1999.

Table 2-11: 1999 Non-Energy Fossil Fuel Consumption, Storage, and Emissions (Tg CO_2 Eq. unless otherwise noted)

Sector/Fuel Type	Consumption (TBtu)	Carbon Content	Storage Factor (%)	Carbon Stored	Emissions
Industry	**6,476.86**	**448.04**	**-**	**358.8**	**89.2**
Industrial Coking Coal	24.48	2.29	0.75	1.7	0.6
Natural Gas to Chemical Plants	754.32	40.02	-	17.9	22.1
Nitrogenous Fertilizers	381.72	20.25	-	-	20.3
Other Uses	372.60	19.77	0.91	17.9	1.9
Asphalt & Road Oil	1,324.41	100.13	1.00	100.1	-
LPG	1,807.12	111.82	0.91	101.2	10.6
Lubricants	192.80	14.31	0.09	1.3	13.0
Pentanes Plus	331.68	22.18	0.91	20.1	2.1
Petrochemical Feedstocks	1,313.22	92.73	-	83.9	8.8
Naphtha (<401 deg. F)	502.08	33.39	0.91	30.2	3.2
Other Oil (>401 deg. F)	811.14	59.34	0.91	53.7	5.6
Still Gas	-	-	0.80	-	-
Petroleum Coke	376.80	38.48	0.50	19.2	19.2
Special Naphtha	145.40	10.59	-	-	10.6
Distillate Fuel Oil	6.99	0.51	0.50	0.3	0.3
Residual Fuel	50.30	3.96	0.50	2.0	2.0
Waxes	37.44	2.72	1.00	2.7	-
Miscellaneous Products	111.91	8.28	1.00	8.3	-
Transportation	**182.10**	**13.51**	**-**	**1.2**	**12.3**
Lubricants	182.10	13.51	0.09	1.2	12.3
U.S. Territories	**227.42**	**16.68**	**-**	**1.7**	**15.0**
Lubricants	1.39	0.10	0.09	+	0.1
Other Petroleum (Misc. Prod.)	226.03	16.58	0.10	1.7	14.9
Total	**6,886.38**	**478.23**	**-**	**361.7**	**116.5**

+ Less than 0.05 Tg CO_2 Eq.
- Not applicable.
Note: Totals may not sum due to independent rounding.

Table 2-12: Storage and Emissions from Non-Energy Fossil Fuel Consumption (Tg CO_2 Eq.)

Variable	1990	1995	1996	1997	1998	1999
Potential Emissions	357.6	406.8	417.4	434.5	450.5	478.2
Carbon Stored	276.2	317.9	323.1	338.6	343.4	361.7
Emissions	81.4	88.9	94.3	95.9	107.1	116.5

Methodology

The first step in estimating carbon stored in products was to determine the aggregate quantity of fossil fuels diverted to feedstock uses from energy-related combustion uses. The carbon content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific carbon content values (see Annex A).

Next, the amount of carbon stored was estimated by multiplying the potential emissions by a storage factor, which were calculated using U.S. data on carbon flows. For asphalt and road oil, petrochemical feedstocks, liquid petroleum gases (LPG), pentanes plus, and natural gas for other uses, carbon storage factors were calculated as the ratio of (a) the carbon stored by the fuel's non-energy products to (b) the total carbon content of the fuel consumed. A lifecycle approach was used in the development of these storage factors in order to account for losses in the production process—from raw material acquisition through manufacturing and processing—and during use. Details of these calculations are shown in Annex B. Because losses associated with waste management are handled separately in the Waste chapter, the storage factors do not account for losses at the disposal end of the life cycle. For the other fuel types, the storage factors were taken directly from Marland and Rotty (1984).

Lastly, emissions were estimated by subtracting the carbon stored from the potential emissions.

Data Sources

Non-energy fuel consumption and carbon content data were supplied by the EIA (2000). Where storage factors were calculated specifically for the United States, data was obtained on fuel products such as asphalt, plastics, synthetic rubber, synthetic fibers, pesticides, and solvents. Data was taken from a variety of industry sources, government reports, and expert communications. Sources include EPA compilations of air emission factors (EPA 1995, EPA 2000c), the National Asphalt Pavement Association (Connolly 2000), the Emissions Inventory Improvement Program (EIIP 1999), the U.S. Census Bureau (1999), the American Plastics Council (APC 2000), the International Institute of Synthetic Rubber Products (IISRP 2000), the Fiber Economics Bureau (FEB 2000), and the Chemical Manufacturer's Handbook (CMA 1999). For the other fuel types, storage factors were taken from Marland and Rotty (1984). Specific data sources are listed in full detail in Annex B.

Uncertainty

The fuel consumption data and the carbon content values employed here were taken from the same references as the data used for estimating overall CO_2 emissions from fossil fuel combustion. Given that the uncertainty in these data is expected to be small, the uncertainty of the estimate for the potential carbon emissions is also expected to be small. However, there is a large degree of uncertainty in the storage factors employed, depending upon the fuel type. For each of the calculated storage factors, the uncertainty is discussed in detail in Annex B. Generally, uncertainty arises from assumptions made to link fuel types with their derivative products and in determining the fuel products' carbon contents and emission or storage fates. The storage factors from Marland and Rotty (1984) are also highly uncertain.

Stationary Combustion (excluding CO_2)

Stationary combustion encompasses all fuel combustion activities except those related to transportation (i.e., mobile combustion). Other than carbon dioxide (CO_2), which was addressed in the previous section, gases from stationary combustion include the greenhouse gases methane (CH_4) and nitrous oxide (N_2O) and the criteria pollutants nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs).[32] Emissions of these gases from stationary combustion sources depend upon fuel characteristics, technology type, usage of pollution control equipment, and ambient environmental conditions. Emissions also vary with the size and vintage of the combustion technology as well as maintenance and operational practices.

Nitrous oxide and NO_x emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Carbon monoxide emissions from stationary combustion are generally a function of the efficiency of combustion and the use of emission controls; they are highest when less oxygen is present in the air-fuel mixture than is necessary for complete combustion. These conditions are most likely to occur during start-up and shut-down and during fuel switching (e.g., the switching of coal grades at a coal-burning electric utility plant). Methane and NMVOC emissions from stationary combustion are primarily a function of the CH_4 content of the fuel, combustion efficiency, and post-combustion controls.

Emissions of CH_4 increased slightly from 1990 to 1996, but fell to just below the 1990 level in 1999 to 8.1 Tg CO_2 Eq. (386 Gg). This decrease in emissions was primarily due to lower wood consumption in the residential sector. Nitrous oxide emissions rose 15 percent since 1990 to 15.7 Tg CO_2 Eq. (51 Gg) in 1999. The largest source of N_2O emissions was coal combustion by electric utilities, which alone accounted for 53 percent of total N_2O emis-

[32] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex M.

sions from stationary combustion in 1999. Overall, though, stationary combustion is a small source of CH_4 and N_2O in the United States.

In contrast, stationary combustion was a significant source of NO_x emissions, but a smaller source of CO and NMVOCs. In 1999, emissions of NO_x from stationary combustion represented 39 percent of national NO_x emissions, while CO and NMVOC emissions from stationary combustion contributed approximately 6 and 5 percent, respectively, to the national totals. From 1990 to 1999, emissions of NO_x, CO, and NMVOCs decreased by 8, 4, and 10 percent, respectively.

The decrease in NO_x emissions from 1990 to 1999 are mainly due to decreased emissions from electric utilities. Decreases in CO and NMVOC emissions over this time period can largely be attributed to decreased residential wood consumption, which is the most significant source of these pollutants from stationary combustion. Table 2-13 through and Table 2-16 provide CH_4 and N_2O emission estimates from stationary combustion by sector and fuel type. Estimates of NO_x, CO, and NMVOC emissions in 1998 are given in Table 2-17.[33]

Methodology

Methane and nitrous oxide emissions were estimated by multiplying emission factors (by sector and fuel type) by fossil fuel and wood consumption data. National coal, natural gas, fuel oil, and wood consumption data were grouped into four sectors—industrial, commercial/institutional, residential, and electric utilities.

For NO_x, CO, and NMVOCs, the major categories included in this section are those used in EPA (2000): coal, fuel oil, natural gas, wood, other fuels (including LPG, coke, coke oven gas, and others), and stationary internal combustion. The EPA estimates emissions of NO_x, CO, and NMVOCs by sector and fuel source using a "bottom-up" estimating procedure. In other words, emissions were calculated either for individual sources (e.g., indus-

Table 2-13: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990		1995	1996	1997	1998	1999
Electric Utilities	**0.5**		**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
Coal	0.3		0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.1		+	+	0.1	0.1	0.1
Natural gas	0.1		0.1	0.1	0.1	0.1	0.1
Wood	+		+	+	+	+	+
Industrial	**2.7**		**3.0**	**3.0**	**3.1**	**3.0**	**3.3**
Coal	0.6		0.5	0.5	0.5	0.5	0.5
Fuel Oil	0.4		0.4	0.4	0.4	0.4	0.4
Natural gas	0.8		1.0	1.0	1.0	1.0	1.0
Wood	0.9		1.1	1.1	1.1	1.1	1.4
Commercial/Institutional	**0.7**		**0.7**	**0.8**	**0.8**	**0.7**	**0.8**
Coal	+		+	+	+	+	+
Fuel Oil	0.2		0.2	0.2	0.1	0.1	0.1
Natural gas	0.3		0.3	0.3	0.3	0.3	0.3
Wood	0.2		0.3	0.3	0.3	0.3	0.3
Residential	**4.6**		**4.7**	**4.7**	**3.8**	**3.3**	**3.5**
Coal	0.4		0.3	0.3	0.4	0.3	0.3
Fuel Oil	0.3		0.3	0.3	0.3	0.3	0.3
Natural Gas	0.5		0.5	0.5	0.5	0.5	0.5
Wood	3.5		3.6	3.6	2.6	2.3	2.4
Total	**8.5**		**8.9**	**9.0**	**8.1**	**7.6**	**8.1**

\+ Does not exceed 0.05 Tg CO_2 Eq.
NA (Not Available)
Note: Totals may not sum due to independent rounding

[33] See Annex C for a complete time series of criteria pollutant emission estimates for 1990 through 1999.

Table 2-14: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990		1995	1996	1997	1998	1999
Electric Utilities	**7.4**		**7.8**	**8.2**	**8.5**	**8.7**	**8.6**
Coal	7.1		7.6	8.0	8.2	8.4	8.4
Fuel Oil	0.2		0.1	0.1	0.2	0.2	0.2
Natural Gas	0.1		0.1	0.1	0.1	0.1	0.1
Wood	+		+	+	+	+	+
Industrial	**4.8**		**5.1**	**5.2**	**5.3**	**5.2**	**5.8**
Coal	1.2		1.1	1.0	1.0	1.0	1.0
Fuel Oil	1.6		1.6	1.7	1.7	1.7	1.8
Natural Gas	0.3		0.3	0.3	0.3	0.3	0.3
Wood	1.8		2.1	2.1	2.2	2.3	2.8
Commercial/Institutional	**0.3**		**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	+		+	+	+	+	+
Fuel Oil	0.2		0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1		0.1	0.1	0.1	0.1	0.1
Wood	+		0.1	0.1	0.1	0.1	0.1
Residential	**1.1**		**1.1**	**1.2**	**1.0**	**0.8**	**0.9**
Coal	+		+	+	+	+	+
Fuel Oil	0.2		0.3	0.3	0.3	0.2	0.3
Natural Gas	0.1		0.1	0.2	0.2	0.1	0.1
Wood	0.7		0.7	0.7	0.5	0.4	0.5
Total	**13.6**		**14.3**	**14.9**	**15.0**	**15.1**	**15.7**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 2-15: CH_4 Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990		1995	1996	1997	1998	1999
Electric Utilities	**23**		**23**	**23**	**25**	**26**	**25**
Coal	16		17	18	19	19	19
Fuel Oil	4		2	2	2	4	3
Natural Gas	3		3	3	3	3	3
Wood	+		+	+	+	+	+
Industrial	**129**		**141**	**143**	**145**	**144**	**157**
Coal	27		25	24	24	23	22
Fuel Oil	17		17	18	19	18	19
Natural Gas	40		48	50	50	48	48
Wood	44		50	52	53	55	67
Commercial/Institutional	**33**		**36**	**38**	**37**	**35**	**39**
Coal	1		1	1	1	1	1
Fuel Oil	9		7	7	7	7	7
Natural Gas	13		15	15	16	15	15
Wood	11		13	14	13	13	16
Residential	**218**		**223**	**226**	**179**	**156**	**165**
Coal	19		16	16	17	13	13
Fuel Oil	13		14	15	14	13	14
Natural Gas	21		24	26	24	22	23
Wood	166		170	170	123	107	115
Total	**403**		**422**	**430**	**386**	**361**	**386**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.

Table 2-16: N_2O Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990		1995	1996	1997	1998	1999
Electric Utilities	**24**		**25**	**27**	**27**	**28**	**28**
Coal	23		24	26	27	27	27
Fuel Oil	1		+	+	+	1	1
Natural Gas	+		+	+	+	+	+
Wood	+		+	+	+	+	+
Industrial	**16**		**16**	**17**	**17**	**17**	**19**
Coal	4		3	3	3	3	3
Fuel Oil	5		5	5	6	6	6
Natural Gas	1		1	1	1	1	1
Wood	6		7	7	7	7	9
Commercial/Institutional	**1**		**1**	**1**	**1**	**1**	**1**
Coal	+		+	+	+	+	+
Fuel Oil	1		+	+	+	+	+
Natural Gas	+		+	+	+	+	+
Wood	+		+	+	+	+	+
Residential	**3**		**4**	**4**	**3**	**3**	**3**
Coal	+		+	+	+	+	+
Fuel Oil	1		1	1	1	1	1
Natural Gas	+		+	1	+	+	+
Wood	2		2	2	2	1	2
Total	**44**		**46**	**48**	**49**	**49**	**51**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding

trial boilers) or for multiple sources combined, using basic activity data as indicators of emissions. Depending on the source category, these basic activity data may include fuel consumption, fuel deliveries, tons of refuse burned, raw material processed, etc.

The EPA derived the overall emission control efficiency of a source category from published reports, the 1985 National Acid Precipitation and Assessment Program (NAPAP) emissions inventory, and other EPA databases. The U.S. approach for estimating emissions of NO_x, CO, and NMVOCs from stationary combustion, as described above, is consistent with the methodology recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997).

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex C.

Data Sources

Emissions estimates for NO_x, CO, and NMVOCs in this section were taken directly from the EPA's *National Air Pollutant Emissions Trends: 1900 - 1999* (EPA 2000). Fuel consumption data for CH_4 and N_2O estimates were provided by the U.S. Energy Information Administration's Annual Energy Review (EIA 2000). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc. that are reported as biomass by EIA. Emission factors were provided by the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997).

Uncertainty

Methane emission estimates from stationary sources are highly uncertain, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O

Table 2-17: NO_x, CO, and NMVOC Emissions from Stationary Combustion in 1999 (Gg)

Sector/Fuel Type	NO_x	CO	NMVOC
Electric Utilities	**5,161**	**374**	**49**
Coal	4,477	217	26
Fuel Oil	183	16	5
Natural Gas	349	85	8
Wood	NA	NA	NA
Internal Combustion	152	55	10
Industrial	**2,844**	**1,069**	**162**
Coal	492	99	6
Fuel Oil	194	47	7
Natural Gas	1,090	310	54
Wood	NA	NA	NA
Other Fuels[a]	107	309	32
Internal Combustion	961	303	63
Commercial/Institutional	**373**	**136**	**26**
Coal	34	14	1
Fuel Oil	73	15	3
Natural Gas	241	63	14
Wood	NA	NA	NA
Other Fuels[a]	25	45	9
Residential	**692**	**3,220**	**582**
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	36	2,994	552
Other Fuels[c]	656	226	31
Total	**9,070**	**4,798**	**820**

NA (Not Available)
[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2000).
[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2000).
[c] "Other Fuels" include LPG, waste oil, coke oven gas, and coke (EPA 2000).
Note: Totals may not sum due to independent rounding. See Annex C for emissions in 1990 through 1999.

emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control). The uncertainties associated with the emission estimates of these gases are greater than with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the criteria pollutants, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Mobile Combustion (excluding CO_2)

Mobile combustion emits greenhouse gases other than CO_2, including methane (CH_4), nitrous oxide (N_2O), and the criteria pollutants carbon monoxide (CO), nitrogen oxides (NO_x), and non-methane volatile organic compounds (NMVOCs).

As with stationary combustion, N_2O and NO_x emissions are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, as well as usage of pollution control equipment. Nitrous oxide, in particular, can be formed by the catalytic processes used to control NO_x CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. This occurs especially in idle, low speed and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions, such as catalytic converters.

Emissions from mobile combustion were estimated by transport mode (e.g., highway, air, rail, and water) and fuel type—motor gasoline, diesel fuel, jet fuel, aviation gas, natural gas, liquefied petroleum gas (LPG), and residual fuel oil—and vehicle type. Road transport accounted for the majority of mobile source fuel consumption, and hence, the majority of mobile combustion emissions. Table 2-18 through Table 2-21 provide CH_4 and N_2O emission estimates from mobile combustion by vehicle type, fuel type, and transport mode. Estimates of NO_x, CO, and NMVOC emissions in 1999 are given in Table 2-22.[34]

[34] See Annex C for a complete time series of criteria pollutant emission estimates for 1990 through 1998.

Table 2-18: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	1996	1997	1998	1999
Gasoline Highway	**4.3**	**4.2**	**4.0**	**4.0**	**3.9**	**3.8**
Passenger Cars	2.4	2.0	2.0	2.0	1.9	1.9
Light-Duty Trucks	1.6	1.9	1.6	1.6	1.5	1.4
Heavy-Duty Vehicles	0.3	0.2	0.4	0.4	0.3	0.3
Motorcycles	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Diesel Highway	0.2	0.2	0.3	0.3	0.3	0.3
Passenger Cars	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+
Heavy-Duty Vehicles	0.2	0.2	0.3	0.3	0.3	0.3
Non-Highway	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Ships and Boats	0.1	0.1	0.1	0.1	0.1	0.1
Locomotives	0.1	0.1	0.1	0.1	+	+
Farm Equipment	0.1	0.1	0.1	0.1	0.1	0.1
Construction Equipment	+	+	+	+	+	+
Aircraft	0.2	0.1	0.1	0.2	0.1	0.2
Other*	+	+	+	+	+	+
Total	**5.0**	**4.9**	**4.8**	**4.7**	**4.6**	**4.5**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-19: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	1996	1997	1998	1999
Gasoline Highway	**49.6**	**61.7**	**59.3**	**59.2**	**58.2**	**57.2**
Passenger Cars	30.9	33.0	32.7	32.4	32.1	31.5
Light-Duty Trucks	17.8	27.1	23.9	24.0	23.3	22.7
Heavy-Duty Vehicles	0.9	1.6	2.7	2.8	2.8	3.0
Motorcycles	+	+	+	+	+	+
Diesel Highway	**1.8**	**2.2**	**2.9**	**3.1**	**3.1**	**3.2**
Passenger Cars	0.1	0.1	+	+	+	+
Light-Duty Trucks	+	0.1	+	+	+	+
Heavy-Duty Vehicles	1.6	2.0	2.9	3.0	3.1	3.2
Non-Highway	**2.9**	**3.0**	**3.0**	**2.9**	**2.8**	**3.0**
Ships and Boats	0.4	0.5	0.4	0.3	0.3	0.4
Locomotives	0.3	0.3	0.3	0.2	0.2	0.2
Farm Equipment	0.3	0.3	0.3	0.3	0.3	0.3
Construction Equipment	0.1	0.1	0.1	0.2	0.2	0.1
Aircraft	1.7	1.7	1.8	1.7	1.8	1.8
Other*	0.1	0.1	0.1	0.1	0.1	0.1
Total	**54.3**	**66.8**	**65.3**	**65.2**	**64.2**	**63.4**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-20: CH_4 Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990		1995	1996	1997	1998	1999
Gasoline Highway	**207**		**199**	**192**	**189**	**184**	**179**
Passenger Cars	115		95	94	93	93	92
Light-Duty Trucks	76		89	76	75	72	68
Heavy-Duty Vehicles	12		11	17	17	16	16
Motorcycles	4		4	4	3	3	3
Diesel Highway	**10**		**11**	**16**	**16**	**16**	**16**
Passenger Cars	+		+	+	+	+	+
Light-Duty Trucks	+		+	+	+	+	+
Heavy-Duty Vehicles	9		11	15	16	16	16
Non-Highway	**21**		**21**	**21**	**20**	**19**	**20**
Ships and Boats	3		4	4	3	2	4
Locomotives	3		3	3	2	2	2
Farm Equipment	6		6	6	6	5	5
Construction Equipment	1		1	1	1	1	1
Aircraft	7		7	7	7	7	7
Other*	1		1	1	1	1	1
Total	**237**		**232**	**228**	**225**	**219**	**215**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-21: N_2O Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990		1995	1996	1997	1998	1999
Gasoline Highway	**160**		**199**	**191**	**191**	**188**	**184**
Passenger Cars	100		106	105	104	103	102
Light-Duty Trucks	57		87	77	77	75	73
Heavy-Duty Vehicles	3		5	9	9	9	10
Motorcycles	+		+	+	+	+	+
Diesel Highway	**6**		**7**	**9**	**10**	**10**	**10**
Passenger Cars	+		+	+	+	+	+
Light-Duty Trucks	+		+	+	+	+	+
Heavy-Duty Vehicles	5		6	9	10	10	10
Non-Highway	**9**		**10**	**10**	**9**	**9**	**10**
Ships and Boats	1		1	1	1	1	1
Locomotives	1		1	1	1	1	1
Farm Equipment	1		1	1	1	1	1
Construction Equipment	+		+	+	+	+	+
Aircraft	6		5	6	6	6	6
Other*	+		+	+	+	+	+
Total	**175**		**215**	**211**	**210**	**207**	**204**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-22: NO_x, CO, and NMVOC Emissions from Mobile Combustion in 1999 (Gg)

Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,496**	**43,327**	**4,544**
Passenger Cars	2,582	24,664	2,604
Light-Duty Trucks	1,486	14,620	1,562
Heavy-Duty Vehicles	416	3,866	340
Motorcycles	12	177	38
Diesel Highway	**3,297**	**2,023**	**263**
Passenger Cars	7	7	3
Light-Duty Trucks	5	5	2
Heavy-Duty Vehicles	3,284	2,011	258
Non-Highway	**5,001**	**22,829**	**2,929**
Ships and Boats	975	2,170	874
Locomotives	1,092	108	44
Farm Equipment	826	458	99
Construction Equipment	1,137	1,333	214
Aircraft[a]	159	909	166
Other[b]	813	17,851	1,532
Total	**12,794**	**68,179**	**7,736**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Mobile combustion was responsible for a small portion of national CH_4 emissions but was the second largest source of N_2O in the United States. From 1990 to 1999, CH_4 emissions declined by 10 percent, to 4.5 Tg CO_2 Eq. (215 Gg). Nitrous oxide emissions, however, rose 17 percent to 63.4 Tg CO_2 Eq. (204 Gg) (see Figure 2-20). The reason for this conflicting trend was that the control technologies employed on highway vehicles in the United States lowered CO, NO_x, NMVOC, and CH_4 emissions, but resulted in higher average N_2O emission rates. Fortunately, since 1994 improvements in the emission control technologies installed on new vehicles have reduced emission rates of both NO_x and N_2O per vehicle mile traveled. Overall, CH_4 and N_2O emissions were dominated by gasoline-fueled passenger cars and light-duty gasoline trucks.

Fossil-fueled motor vehicles comprise the single largest source of CO emissions in the United States and are a significant contributor to NO_x and NMVOC emissions. In 1999, CO emissions from mobile combustion contributed 82 percent of national CO emissions and 56 and 48 percent of NO_x and NMVOC emissions, respectively. Since 1990, emissions of CO and NMVOCs from mobile combustion decreased by 2 and 5 percent, respectively, while emissions of NO_x increased by 17 percent.

Methodology

Estimates for CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each category. Depending upon the category, activity data included such information as fuel consumption, fuel deliveries, and vehicle miles traveled (VMT). Emission estimates from highway vehicles were based on VMT and emission factors by vehicle type, fuel type, model year, and control technology. Fuel consumption data was employed as a measure of activity for non-highway vehicles and then fuel-specific emission factors were applied.[35] A complete discussion of the methodology used to estimate emissions from mobile combustion is provided in Annex D.

The EPA (2000b) provided emissions estimates of NO_x, CO, and NMVOCs for eight categories of highway vehicles,[36] aircraft, and seven categories of off-highway vehicles.[37]

Data Sources

Emission factors used in the calculations of CH_4 and N_2O emissions are presented in Annex D. The *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) provided emission factors for CH_4, and were developed using MOBILE5a, a model used by the Environmental Protection Agency (EPA) to estimate exhaust and running loss emissions from highway vehicles. The MOBILE5a model uses information on ambient tempera-

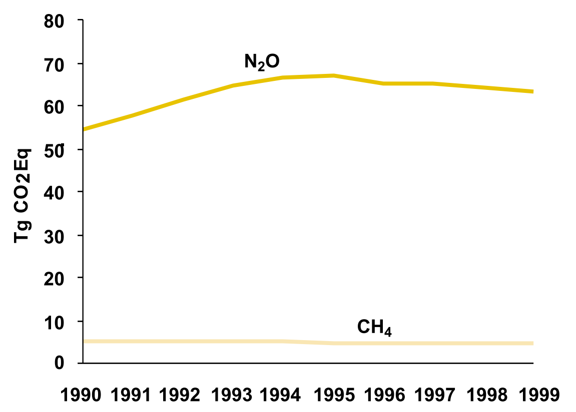
[35] The consumption of international bunker fuels is not included in these activity data, but are estimated separately under the International Bunker Fuels source category.

[36] These categories included: gasoline passenger cars, diesel passenger cars, light-duty gasoline trucks less than 6,000 pounds in weight, light-duty gasoline trucks between 6,000 and 8,500 pounds in weight, light-duty diesel trucks, heavy-duty gasoline trucks and buses, heavy-duty diesel trucks and buses, and motorcycles.

[37] These categories included: gasoline and diesel farm tractors, other gasoline and diesel farm machinery, gasoline and diesel construction equipment, snowmobiles, small gasoline utility engines, and heavy-duty gasoline and diesel general utility engines.

Figure 2-20

Mobile Source CH_4 and N_2O Emissions



ture, vehicle speeds, national vehicle registration distributions, gasoline volatility, and other variables in order to produce these factors (EPA 1997).

Emission factors for N_2O from gasoline highway vehicles came from EPA (1998). This report contains emission factors for older passenger cars—roughly pre-1992 in California and pre-1994 in the rest of the United States—from published references, and for newer cars from a recent testing program at EPA's National Vehicle and Fuel Emissions Laboratory (NVFEL). These emission factors for gasoline highway vehicles are lower than the U.S. default values in the *Revised 1996 IPCC Guidelines*, but are higher than the European default values, both of which were published before the more recent tests and literature review conducted by the NVFEL. The U.S. default values in the *Revised 1996 IPCC Guidelines* were based on three studies that tested a total of five cars using European rather than U.S. test protocols. More details may be found in EPA (1998).

Emission factors for gasoline vehicles other than passenger cars were scaled from those for passenger cars with the same control technology, based on their relative fuel economy. This scaling was supported by limited data showing that light-duty trucks emit more N_2O than passenger cars with equivalent control technology. The use of fuel-consumption ratios to determine emission factors is considered a temporary measure only; to be replaced as additional testing data are available. For more details, see EPA (1998). Nitrous oxide emission factors for diesel highway vehicles were taken from the European default values found in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). There is little data addressing N_2O emissions from U.S. diesel-fueled vehicles, and in general, European countries have had more experience with diesel-fueled vehicles. U.S. default values in the *Revised 1996 IPCC Guidelines* were used for non-highway vehicles.

Activity data were gathered from several U.S. government sources including EIA (2000a), EIA (2000b), FHWA (1999), BEA (2000), DESC (2000), DOC (2000), FAA (2000), and DOT/BTS (2000). Control technology data for highway vehicles were obtained from the EPA's Office of Transportation and Air Quality. Annual VMT data for 1990 through 1999 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database, as noted in EPA (2000a).

Emissions estimates for NO_x, CO, NMVOCs were taken directly from the EPA's *National Air Pollutant Emissions Trends,* 1900 - 1999 (EPA 2000b).

Uncertainty

Mobile combustion emission estimates can vary significantly due to assumptions concerning fuel type and composition, technology type, average speeds, type of emission control equipment, equipment age, and operating and maintenance practices. Fortunately, detailed activity data for mobile combustion were available, including VMT by vehicle type for highway vehicles. The allocation of this VMT to individual model years was done using temporally variable profiles of both vehicle usage by vehicle age and vehicle usage by model year in the United States. Data for these profiles were provided by EPA (2000a).

Average emission factors were developed based on numerous assumptions concerning the age and model of vehicle; percent driving in cold start, warm start, and cruise conditions; average driving speed; ambient temperature; and maintenance practices. The factors for regulated emissions from mobile combustion—CO, NO_x, and hydrocarbons—have been extensively researched, and thus involve lower uncertainty than emissions of unregulated gases. Although methane has not been singled out for regulation in the United States, overall hydrocarbon emissions from mobile combustion—a component of which is methane—are regulated.

In calculating CH_4 and N_2O emissions from highway vehicles, only data for Low Emission Vehicles (LEVs) in California has been obtained. Data on the number of LEVs in the rest of the United States will be researched and may be included in future inventories.

Compared to methane, CO, NO_x, and NMVOCs, there is relatively little data available to estimate emission factors for nitrous oxide. Nitrous oxide is not a criteria pollutant, and measurements of it in automobile exhaust have not been routinely collected. Research data has shown that N_2O emissions from vehicles with catalytic converters are greater than those without emission controls, and that vehicles with aged catalysts emit more than new ones. The emission factors used were, therefore, derived from aged cars (EPA 1998). The emission factors used for Tier 0 and older cars were based on tests of 28 vehicles; those for newer vehicles were based on tests of 22 vehicles. This sample is small considering that it is being used to characterize the entire U.S. fleet, and the associated uncertainty is therefore large. Currently, N_2O gasoline highway emission factors for vehicles other than passenger cars are scaled based on those for passenger cars and their relative fuel economy. Actual measurements should be substituted for this procedure when they become available. Further testing is needed to reduce the uncertainty in emission factors for all classes of vehicles, using realistic driving regimes, environmental conditions, and fuels.

Overall, uncertainty for N_2O emissions estimates is considerably higher than for CH_4, CO, NO_x, or NMVOC; however, all these gases involve far more uncertainty than CO_2 emissions from fossil fuel combustion.

U.S. jet fuel and aviation gasoline consumption is currently all attributed to the transportation sector by EIA, and it is assumed here that it is all used to fuel aircraft. However, it is likely that some fuel purchased by airlines is not necessarily used in aircraft, but instead used to power auxiliary power units, in ground equipment, and to test engines. Some jet fuel may also be used for other purposes such as blending with diesel fuel or heating oil.

In calculating CH_4 emissions from aircraft, an average emission factor is applied to total jet fuel consumption. This average emission factor takes into account the fact that CH_4 emissions occur only during the landing and take-off (LTO) cycles, with no CH_4 being emitted during the cruise cycle. While there is some evidence that fuel emissions in cruise conditions may actually destroy methane, the average emission factor used does not take this into account.

Lastly, in EPA (2000b), U.S. aircraft emission estimates for CO, NOx, and NMVOCs are based upon landing and take-off (LTO) cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates presented here overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including LTO cycles by aircraft on international flights but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes.

Coal Mining

All underground and surface coal mining liberates methane as part of normal operations. The amount of methane liberated depends upon the amount that remains in the coal ("*in situ*") and surrounding strata when mining occurs. This methane content depends upon the amount of methane created during the coal formation (or coalification) process, and the geologic characteristics of the coal seams. Deeper coal deposits tend to generate more methane during coalification and retain more of the gas afterwards. Accordingly, deep underground coal seams generally have higher methane contents than shallow coal seams or surface deposits.

Three types of coal mining activities release methane to the atmosphere: underground mining, surface mining, and post-mining activities. Underground coal mines contribute the largest share of methane emissions. All underground coal mines employ ventilation systems to ensure that methane levels remain within safe concentrations. These systems can exhaust significant amounts of methane to the atmosphere in low concentrations. Additionally, twenty gassy U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of methane before, during or after mining. In 1999, 11 coal mines collected methane from degasification systems and sold this gas to a pipeline, thus reducing emissions to the atmosphere. Surface coal mines also release methane as the overburden is removed and the coal is exposed; however, the level of emissions is much lower than from underground mines. Finally, some of the methane retained in the coal after mining is released during processing, storage, and transport of the coal.

Total methane emissions in 1999 were estimated to be 61.8 Tg CO_2 Eq. (2,944 Gg), declining 30 percent since 1990 (see Table 2-23 and Table 2-24). Of this amount, underground mines accounted for 64 percent, surface mines accounted for 14 percent, and post-mining emissions accounted for 21 percent. With the exception of 1994 and 1995, total methane emissions declined in each successive year during this period. In 1993, methane generated from underground mining dropped, primarily due to labor strikes at many large underground mines. In 1995, there was an increase in methane emissions from underground mining due to particularly increased emissions at the highest-emitting coal mine in the country. The decline in methane emissions from underground mines in 1999 is the result of a decrease in coal production, and the mining of less gassy coal. Surface mine emissions and post-mining emissions remained relatively constant from 1990 to 1999.

In 1994, EPA's Coalbed Methane Outreach Program (CMOP) began working with the coal industry and other stakeholders to identify and remove obstacles to investments in coal mine methane recovery and use projects. Emissions reductions attributed to CMOP are estimated at 0.8, 5.1, 5.5, 6.6, 6.2, and 7.0 Tg CO_2 Eq. in 1994 through 1999, respectively.

Methodology

The methodology for estimating methane emissions from coal mining consists of two steps. The first step involves estimating methane emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emissions factors.

Table 2-23: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	1990		1995	1996	1997	1998	1999
Underground Mining	62.8		52.2	46.3	45.0	43.0	39.8
Liberated	68.8		64.8	60.4	61.7	60.6	57.2
Recovered & Used	(6.0)		(12.6)	(14.1)	(16.7)	(17.5)	(17.4)
Surface Mining	10.2		8.9	9.2	9.5	9.4	8.8
Post- Mining (Underground)	13.1		11.9	12.4	12.8	12.6	11.7
Post-Mining (Surface)	1.7		1.5	1.5	1.5	1.5	1.4
Total	**87.9**		**74.6**	**69.3**	**68.8**	**66.5**	**61.8**

Note: Totals may not sum due to independent rounding.

Table 2-24: CH_4 Emissions from Coal Mining (Gg)

Activity	1990		1995	1996	1997	1998	1999
Underground Mining	2,991		2,487	2,204	2,141	2,049	1,896
Liberated	3,278		3,086	2,875	2,938	2,884	2,726
Recovered & Used	(288)		(599)	(671)	(797)	(835)	(829)
Surface Mining	488		425	436	451	446	421
Post- Mining (Underground)	626		569	590	609	600	558
Post-Mining (Surface)	79		69	71	73	72	68
Total	**4,184**		**3,550**	**3,301**	**3,274**	**3,168**	**2,944**

Note: Totals may not sum due to independent rounding.

Underground mines. Total methane emitted from underground mines was estimated as the sum of methane liberated from ventilation systems, plus methane liberated from degasification systems, minus methane recovered and used. The Mine Safety and Heath Administration (MSHA) samples methane emissions from ventilation systems for all mines with detectable[38] methane concentrations. These mine-by-mine measurements are used to estimate methane emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove methane before, during, or after mining. This methane can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of methane collected by each of the more than twenty mines using these systems, depending on available data. For example, some mines report to EPA the amounts of methane liberated from their degasification systems. For mines that sell recovered methane to a pipeline, pipeline sales data were used to estimate degasification emissions. Finally, for those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of methane recovered by degasification systems and then used (i.e., not vented) was estimated. This calculation was complicated by the fact that methane is rarely recovered and used during the same year in which the particular coal seam is mined. In 1999, 11 active coal mines sold recovered methane to pipelines. Emissions avoided for these projects were estimated using gas sales data reported by various State agencies, and information supplied by coal mine operators regarding the number of years in advance of mining that gas recovery occurs. Additionally, some of the State agencies provide individual well production information, which was used to assign gas sales to a particular year.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining methane emissions were estimated by multiplying basin-specific coal production by basin-specific emissions factors. Surface mining emissions factors were developed by assuming that surface mines emit from one to three times as much methane as the average in situ methane content of the coal. This accounts for methane released from the strata surrounding the coal seam. For this analysis, it was assumed that twice the average in-situ methane content was emitted. For post-mining emissions, the emission factor was assumed to be from 25 to 40 percent of the average in situ methane content of coals mined in the basin. For this analysis, it was assumed that 32.5 percent of the average in-situ methane content was emitted.

Data Sources

The Mine Safety and Health Administration provided mine-specific information on methane liberated from ventilation systems at underground mines. The EPA developed estimates of methane liberated from degasification systems at underground mines based on available data for each of the mines employing these systems. The primary sources of data for estimating emissions avoided at underground mines were gas sales data published by State petroleum and natural gas agencies, information supplied by mine operators regarding the number of years in advance of mining that gas recovery occurred, and reports of gas used on-site. Annual coal production data were taken from the Energy Information Administration's *Coal Industry Annual* (see Table 2-25) (EIA 1999). Data on in situ methane content and emissions factors are taken from EPA (1993).

Uncertainty

The emission estimates from underground ventilation systems were based upon actual measurement data, which were estimated to have relatively high accuracy. A degree of imprecision was introduced because the measurements were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used possibly resulted in an average of 10 percent overestimation of annual methane emissions (Mutmansky and Wang 2000). Estimates of methane liberated from degasification systems are less certain because the EPA assigns default recovery efficiencies for a subset of U.S. mines. Compared to underground mines, there is considerably more uncertainty associated

[38] MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

Table 2-25: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,250	546,818	931,068
1991	368,635	532,656	901,291
1992	368,627	534,290	902,917
1993	318,478	539,214	857,692
1994	362,065	575,529	937,594
1995	359,477	577,638	937,115
1996	371,816	593,315	965,131
1997	381,620	607,163	988,783
1998	378,964	634,864	1,013,828
1999[39]	352,753	639,701	992,454

with surface mining and post-mining emissions because of the difficulty in developing accurate emissions factors from field measurements. The EPA plans to update the basin specific surface mining emission factors. Because underground emissions comprise the majority of total coal mining emissions, the overall uncertainty is estimated to be only ±15 percent. Currently, the estimate does not include emissions from abandoned coal mines because of limited data. The EPA is conducting research on the feasibility of including an estimate in future years.

Natural Gas Systems

The U.S. natural gas system is vast, encompassing hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 121.8 Tg CO_2 Eq. (5,799 Gg) of methane in 1999, a slight increase over emissions in 1990 (see Table 2-26 and Table 2-27). Improvements in management practices and technology, along with the normal replacement of older equipment, have helped to stabilize emissions. In addition, EPA's Natural Gas STAR Program, initiated in 1993, is successfully working with the gas industry to promote profiTable practices and technologies that reduce methane emissions.[40]

Methane emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas combusting engine and turbine exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting methane emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of emissions. Emissions from field production accounted for approximately 25 percent of methane emissions from natural gas systems between 1990 and 1999. Emissions rose between 1990 and 1993 but by 1999 had returned to slightly above 1990 levels because of emission reductions by firms participating in the Natural Gas STAR Program.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, are the primary emission source from this stage. Processing plants account for about 12 percent of methane emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive emissions from these compressor stations and from metering and regulating stations account for the majority

[39] The EIA Coal Industry Annual was not yet available, however, total production was available in the U.S. Coal Supply and Demand: 1999 Review. The split between underground and surface mining production is a preliminary estimate based on data from previous years.

[40] Natural Gas STAR Program reductions are included in emission estimates.

Table 2-26: CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	1990		1995	1996	1997	1998	1999
Field Production	29.6		31.0	30.9	29.6	31.7	30.8
Processing	14.7		15.0	14.9	14.9	14.7	14.6
Transmission and Storage	46.7		46.7	47.1	46.0	44.8	44.8
Distribution	30.3		31.5	32.9	32.2	30.9	31.6
Total	**121.2**		**124.2**	**125.8**	**122.7**	**122.1**	**121.8**

Note: Totals may not sum due to independent rounding.

Table 2-27: CH_4 Emissions from Natural Gas Systems (Gg)

Stage	1990		1995	1996	1997	1998	1999
Field Production	1,407		1,477	1,474	1,407	1,510	1,468
Processing	702		712	708	710	698	694
Transmission and Storage	2,223		2,225	2,243	2,192	2,135	2,134
Distribution	1,441		1,498	1,567	1,532	1,471	1,503
Total	**5,772**		**5,912**	**5,993**	**5,841**	**5,814**	**5,799**

Note: Totals may not sum due to independent rounding.

of the emissions from this stage. Pneumatic devices and engine exhaust are also sources of emissions from transmission facilities. Methane emissions from transmission account for approximately 37 percent of the emissions from natural gas systems.

Natural gas is also injected and stored in underground formations during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. Approximately one percent of total emissions from natural gas systems can be attributed to storage facilities.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through mains and service lines to individual end users. There were over 980,000 miles of distribution mains in 1998,[41] an increase from just over 837,000 miles in 1990 (AGA 1998). Distribution system emissions, which account for approximately 26 percent of emissions from natural gas systems, resulted mainly from fugitive emissions from gate stations and non-plastic piping (cast iron, steel).[42] An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage. Distribution system emissions in 1999 were only slightly higher than 1990 levels.

Methodology

The basis for estimates of methane emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 100 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, the EPA developed a 1992 base year emissions estimate using the emission and activity factors. For other years, the EPA has developed a set of industry activity factor drivers that can be used to update activity factors. These drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations.

41 1998 is the latest year for which distribution pipeline mileage data was available.

42 The percentages of total emissions from each stage may not add to 100 because of independent rounding.

The methodology also adjusts the emission factors to reflect underlying technological improvement through both innovation and normal replacement of equipment. For the period 1990 through 1995, the emission factors were held constant. Thereafter, emission factors are reduced at a rate of 0.2 percent per year such that by 2020, emission factors will have declined by 5 percent from 1995. See Annex F for more detailed information on the methodology and data used to calculate methane emissions from natural gas systems.

Data Sources

Activity factor data were obtained from the following sources: American Gas Association (AGA 1991 through 1999); Natural Gas Annual (EIA 1998); Natural Gas Monthly (EIA 1999); Oil and Gas Journal (PennWell Corporation 1999, 2000); Independent Petroleum Association of America (IPAA 1998, 1999), and the Department of Transportation's Office of Pipeline Safety (OPS 2000). The Minerals Management Service (DOI 1997 through 2000) supplied offshore platform data. All emission factors were taken from EPA/GRI (1996).

Uncertainty

The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. Despite the difficulties associated with estimating emissions from this source, the uncertainty in the total estimated emissions are believed to be on the order of ±40 percent.

Petroleum Systems

Methane emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, methane is released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. The EPA estimates that total methane emissions from petroleum systems in 1999 were 21.9 Tg CO_2 Eq. (1,044 Gg). Since 1990, emissions declined gradually primarily due to a decline in domestic oil production. (See Table 2-28 and Table 2-29.) The various sources of emissions are detailed below.

Production Field Operations. Production field operations account for approximately 97 percent of total methane emissions from petroleum systems. Vented methane from oil wells, storage tanks, and related production field processing equipment account for the vast majority of the emissions from production, with storage tanks and natural-gas-powered pneumatic devices being the dominant sources. (The emissions from storage tanks occur when the methane, entrained in crude oil under high pressure, volatilizes once the crude oil is dumped into storage tanks at atmospheric pressure.) The next most dominant sources of venting emissions are oil wells and offshore platforms. The remaining emissions from production can be attributed to fugitives and combustion. The EPA expects future emissions from production fields to decline as the number of oil wells declines and crude production in the United States slows.

Crude Oil Transportation. Crude transportation activities account for approximately one half percent of total methane emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for the majority of methane emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for the remainder.

Crude Oil Refining. Crude oil refining processes and systems account for only two percent of total methane emissions from the oil industry because most of the methane in crude oil is removed or escapes before the crude oil is delivered to the refineries. Within refineries, vented emissions account for about 87 percent of the emissions from refining, while fugitive and combustion emissions account for approximately seven and six percent, respectively. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air to harden it—are the primary venting contributors. Most of the fugitive emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions accumulate from small amounts of unburned methane in process heater stack emissions and from unburned methane

Table 2-28: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	1995	1996	1997	1998	1999
Production Field Operations	**26.5**	**23.9**	**23.3**	**23.3**	**22.6**	**21.2**
Tank venting	11.8	10.4	10.2	10.2	9.8	9.1
Pneumatic device venting	11.7	10.6	10.3	10.3	10.0	9.4
Wellhead fugitives	0.5	0.5	0.5	0.5	0.5	0.5
Combustion & process upsets	1.0	0.9	1.0	1.0	0.9	0.9
Misc. venting & fugitives	1.5	1.4	1.4	1.4	1.3	1.3
Crude Oil Transportation	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**
Total	**27.2**	**24.5**	**24.0**	**24.0**	**23.3**	**21.9**

Note: Totals may not sum due to independent rounding.

Table 2-29: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990	1995	1996	1997	1998	1999
Production Field Operations	**1,263**	**1,136**	**1,111**	**1,109**	**1,075**	**1,011**
Tank venting	564	493	485	484	466	433
Pneumatic device venting	559	507	491	490	475	447
Wellhead fugitives	24	25	25	24	24	24
Combustion & process upsets	46	45	45	46	45	44
Misc. venting & fugitives	70	66	65	65	64	63
Crude Oil Transportation	**7**	**6**	**6**	**6**	**6**	**6**
Refining	**25**	**25**	**26**	**27**	**27**	**27**
Total	**1,294**	**1,168**	**1,143**	**1,142**	**1,108**	**1,044**

Note: Totals may not sum due to independent rounding.

in engine exhausts and flares. The very slight increase in emissions from refining, relative to the decline in emissions from field production operations, is due to increasing imports of crude oil.

Methodology

The EPA's methodology for estimating methane emissions from petroleum systems is based on a comprehensive study of methane emissions from U.S. petroleum systems, *Estimates of Methane Emissions from the U.S. Oil Industry (Draft Report)* (EPA 1999). The study estimates emissions from 70 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 39 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex G explains the emission estimates for these 70 activities in greater detail. The estimates of methane emissions from petroleum systems do not include emissions downstream from oil refineries because these emissions are very small compared to methane emissions upstream from oil refineries.

The methodology for estimating methane emissions from the 70 oil industry activities employs emission and activity factors initially developed in EPA (1999). The EPA estimates emissions for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). The report provides emission factors and activity factors for all activities except those related to offshore oil production. For offshore oil production, the EPA calculates an emission factor by dividing an emission estimate from the Minerals Management Service (MMS) by the number of platforms (the activity factor). Emission factors are held constant for the period 1990 through 1999.

The EPA collects activity factors for 1990 through 1999 from a wide variety of statistical resources. For some years, complete activity factor data are not available. In this case, the EPA employs one of three options. Where appropriate, the activity factor is assumed to be directly proportional to annual oil production. Proportionality constants are calculated by dividing the activity factor for 1995 by the annual oil production for 1995. The resulting proportionality constants are then multiplied by the annual oil production in years for which activity factors must be estimated. In other cases, the activity factor is kept constant from 1990 through 1999. Lastly, previous year data are used when current year data are not yet available. These data are subsequently updated in the next inventory cycle.

Data Sources

Nearly all emission factors were taken from earlier work performed by Radian International LLC (Radian 1996e). Other emission factors were taken from an American Petroleum Institute publication (API 1996), EPA default values, MMS reports (MMS 1995 and 1999), the Exploration and Production (E&P) Tank model (API and GRI), reports by the Canadian Association of Petroleum Producers (CAPP 1992 and 1993), and consensus of industry peer review panels.

The EPA uses many references to obtain activity factors. Among the more important references are the Energy Information Administration annual and monthly reports (EIA 1995, 1996, 1997, 1998), the API Basic Petroleum Data Book (API 1997 and 1999), *Methane Emissions from the Natural Gas Industry* prepared for the Gas Research Institute (GRI) and EPA (Radian 1996a-d), consensus of industry peer review panels, MMS reports (MMS 1995 and 1999), and the *Oil & Gas Journal* (OGJ 1998a,b). Annex G provides a complete list of references.

Uncertainty

The detailed, bottom-up analysis used to evaluate U.S. petroleum systems for the current Inventory reduces the uncertainty related to the methane emission estimates compared to previous estimates. However, a number of uncertainties remain. Published activity factors were not available every year for all 70 activities analyzed for petroleum systems. For example, there is uncertainty associated with the estimate of annual venting emissions in production field operations because a recent census of tanks and other tank battery equipment, such as separators and pneumatic devices, was not available. These uncertainties are important because storage tanks account for 41 percent of total 1999 methane emissions from petroleum systems. Uncertainties are also associated with emission factors because emission rates can vary highly from reservoir to reservoir and well to well. A single summary emission factor cannot reflect this variation. Since the majority of methane emissions occur during production field operations, where methane can first escape crude oil, a better understanding of tanks and tank equipment would reduce the uncertainty. Because of the dominance of crude storage tank venting and pneumatics, Table 2-30 provides emission estimate ranges for these sources. For tank venting, these ranges include numbers that are 25 percent higher than or lower than the given point estimates. For pneumatics, the range is between 33 percent lower than and 25 percent higher than the point estimates.

Natural Gas Flaring and Criteria Pollutant Emissions from Oil and Gas Activities

The flaring of natural gas from oil wells is a small source of carbon dioxide (CO_2). In addition, oil and gas activities also release small amounts of nitrogen oxides (NO_x), carbon monoxide (CO), and nonmethane volatile organic compounds (NMVOCs). This source accounts for only a small proportion of overall emissions of each of these gases. Emissions of CO_2, NO_x, and CO from petroleum and natural gas production activities were all less than 1 percent of national totals, while NMVOC emissions were roughly 2 percent of national totals.

Carbon dioxide emissions from petroleum production result from natural gas that is flared (i.e., combusted) at the production site. Barns and Edmonds (1990) noted that of total reported U.S. venting and flaring, approximately 20 percent may be vented, with the remaining 80 percent flared; however, it is now believed that flaring accounts for an even greater proportion, although some venting still occurs. Methane emissions from venting are accounted for under Petroleum Systems. For 1999, CO_2 emissions from flaring were estimated to be approximately 11.7 Tg CO_2 Eq. (11,701 Gg), an increase of 128 percent since 1990 (see Table 2-31).

Criteria pollutant emissions from oil and gas production, transportation, and storage, constituted a rela-

Table 2-30: Uncertainty in CH_4 Emissions from Production Field Operations (Gg)

Activity	1990		1995	1996	1997	1998	1999
Tank venting (point estimate)	**564**		**493**	**485**	**484**	**466**	**433**
Low	423		370	364	363	349	325
High	705		617	606	605	582	541
Pneumatic devices (point estimate)	**559**		**507**	**491**	**490**	**475**	**447**
Low	372		338	328	327	317	300
High	698		634	614	613	594	559

tively small and stable portion of the total emissions of these gases from the 1990 to 1999 (see Table 2-32).

Methodology

The estimates for CO_2 emissions were prepared using an emission factor of 54.71 Tg CO_2 Eq./QBtu of flared gas, and an assumed flaring efficiency of 100 percent. The quantity of flared gas was estimated as the total reported vented and flared gas minus the amount assumed to be vented annually, which varied from 65,772 million cubic feet in 1990 to 52,670 million cubic feet in 1999.[43]

Criteria pollutant emission estimates for NO_x, CO, and NMVOCs were determined using industry-published production data and applying average emission factors.

Data Sources

Activity data in terms of total natural gas vented and flared for estimating CO_2 emissions from natural gas flaring were taken from EIA's *Natural Gas Annual* (EIA 2000). The emission and thermal conversion factors were also provided by EIA (see Table 2-33).

EPA (2000) provided emission estimates for NO_x, CO, and NMVOCs from petroleum refining, petroleum product storage and transfer, and petroleum marketing operations. Included are gasoline, crude oil and distillate fuel oil storage and transfer operations, gasoline bulk terminal and bulk plants operations, and retail gasoline service stations operations.

Uncertainty

Uncertainties in CO_2 emission estimates primarily arise from assumptions concerning what proportion of natural gas is flared and the flaring efficiency. Uncertainties in criteria pollutant emission estimates are partly due to the accuracy of the emission factors used and projections of growth.

Table 2-31: CO_2 Emissions from Natural Gas Flaring

Year	Tg CO_2 Eq.	Gg
1990	5.1	5,121
1995	13.6	13,587
1996	13.0	12,998
1997	12.0	12,026
1998	10.8	10,839
1999	11.7	11,701

Table 2-32: NO_x, NMVOCs, and CO Emissions from Oil and Gas Activities (Gg)

Year	NO_x	CO	NMVOCs
1990	139	302	555
1995	100	316	582
1996	126	321	433
1997	130	333	442
1998	130	332	440
1999	130	332	385

[43] See the methodological discussion under Petroleum Systems for the basis of the portion of natural gas assumed vented.

International Bunker Fuels

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the United Nations Framework Convention on Climate Change (UNFCCC), are currently not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[44] These decisions are reflected in the *Revised 1996 IPCC Guidelines*, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC/UNEP/OECD/IEA 1997). The Parties to the UNFCCC have yet to decide on a methodology for allocating these emissions.[45]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), carbon monoxide (CO), oxides of nitrogen (NO_x), non-methane volatile organic compounds (NMVOCs), particulate matter, and sulfur dioxide (SO_2).[46] Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine. Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[47]

Emissions of CO_2 from aircraft are essentially a function of fuel use. Methane, N_2O, CO, NO_x, and NMVOC emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Methane, CO, and NMVOCs are the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O and NO_x are primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. The impact of NO_x on atmospheric

Table 2-33: Total Natural Gas Reported Vented and Flared (Million Ft^3) and Thermal Conversion Factor (Btu/Ft^3)

Year	Vented and Flared	Thermal Conversion Factor
1990	150,415	1,106
1991	169,909	1,108
1992	167,519	1,110
1993	226,743	1,106
1994	228,336	1,105
1995	283,739	1,106
1996	272,117	1,109
1997	256,351	1,107
1998	234,472	1,110
1999	245,180	1,111

[44] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c) (contact secretariat@unfccc.de).

[45] Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International civil Aviation Organization.

[46] Sulfur dioxide emissions from jet aircraft and marine vessels, although not estimated here, are mainly determined by the sulfur content of the fuel. In the U.S., jet fuel, distillate diesel fuel, and residual fuel oil average sulfur contents of 0.05, 0.3, and 2.3 percent, respectively. These percentages are generally lower than global averages.

[47] Naphtha-type jet fuel is used primarily by the military in turbojet and turboprop aircraft engines.

chemistry depends on the altitude of the actual emission. The cruising altitude of supersonic aircraft, near or in the ozone layer, is higher than that of subsonic aircraft. At this higher altitude, NO_x emissions contribute to ozone depletion.[48] At the cruising altitudes of subsonic aircraft, however, NO_x emissions contribute to the formation of ozone. At these lower altitudes, the positive radiative forcing effect of ozone is most potent.[49] The vast majority of aircraft NO_x emissions occur at these lower cruising altitudes of commercial subsonic aircraft (NASA 1996).[50]

International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from marine shipping. In comparison to aviation, the atmospheric impacts of NO_x from shipping are relatively minor, as the emissions occur at ground level.

Overall, aggregate greenhouse gas emissions in 1999 from the combustion of international bunker fuels from both aviation and marine activities were 108.3 Tg CO_2 Eq., or 6 percent below emissions in 1990 (see Table 2-34). Although emissions from international flights departing from the United States have increased significantly (30 percent), emissions from international shipping voyages departing the United States appear to have decreased by 31 percent since 1990. Increased military activity during the Persian Gulf War resulted in an increased level of military marine emissions in 1990 and 1991; civilian marine emissions during this period exhibited a similar trend.[51] The majority of these emissions were in the form of carbon dioxide; however, small amounts of CH_4 and N_2O were also emitted. Of the criteria pollutants, emissions of NO_x by aircraft at cruising altitudes are of primary concern because of their effects on ozone formation (see Table 2-35).

Emissions from both aviation and marine international transport activities are expected to grow in the future as both air traffic and trade increase, although emission rates should decrease over time due to technological changes.[52]

Methodology

Emissions of CO_2 were estimated through the application of carbon content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. A complete description of the methodology and a listing of the various factors employed can be found in Annex A. See Annex H for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH_4, N_2O, CO, NO_x, and NMVOCs were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Data Sources

Carbon content and fraction oxidized factors for kerosene-type and naphtha-type jet fuel, distillate fuel oil, and residual fuel oil were taken directly from the Energy Information Administration (EIA) of the U.S. Department of Energy and are presented in Annex A. Heat content and density conversions were taken from EIA (2000) and USAF (1998). Emission factors used in the

[48] In 1996, there were only around a dozen civilian supersonic aircraft in service around the world which flew at these altitudes, however.

[49] However, at this lower altitude, ozone does little to shield the earth from ultraviolet radiation.

[50] Cruise altitudes for civilian subsonic aircraft generally range from 8.2 to 12.5 km (27,000 to 41,000 feet).

[51] See Uncertainty section for a discussion of data quality issues.

[52] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

Table 2-34: Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	1990		1995	1996	1997	1998	1999
CO_2	**114.0**		**101.0**	**102.2**	**109.8**	**112.8**	**107.3**
Aviation	46.7		51.1	52.1	55.9	55.0	61.0
Marine	67.3		49.9	50.1	53.9	57.8	46.4
CH_4	+		+	+	+	+	+
Aviation	+		+	+	+	+	+
Marine	+		+	+	+	+	+
N_2O	**1.0**		**0.9**	**0.9**	**1.0**	**1.0**	**1.0**
Aviation	0.5		0.5	0.5	0.5	0.5	0.6
Marine	0.5		0.4	0.4	0.4	0.4	0.4
Total	**115.0**		**101.9**	**103.1**	**110.8**	**113.8**	**108.3**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 2-35: Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990		1995	1996	1997	1998	1999
CO_2	**114,001**		**101,014**	**102,197**	**109,788**	**112,771**	**107,345**
Aviation	46,728		51,093	52,135	55,899	54,988	60,970
Marine	67,272		49,921	50,062	53,889	57,783	46,376
CH_4	**2**		**2**	**2**	**2**	**2**	**2**
Aviation	1		1	1	2	2	2
Marine	1		0	0	0	1	0
N_2O	**3**		**3**	**3**	**3**	**3**	**3**
Aviation	1		2	2	2	2	2
Marine	2		1	1	1	1	1
CO	**116**		**113**	**115**	**124**	**124**	**128**
Aviation	77		84	86	92	91	100
Marine	39		29	29	32	34	27
NO_x	**1,987**		**1,541**	**1,548**	**1,665**	**1,768**	**1,485**
Aviation	184		202	207	221	218	242
Marine	1,803		1,339	1,341	1,444	1,550	1,243
NMVOC	**59**		**48**	**49**	**52**	**55**	**48**
Aviation	12		13	13	14	14	15
Marine	48		36	36	38	41	33

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

calculations of CH_4, N_2O, CO, NO_x, and NMVOC emissions were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4, 0.1 for N_2O, 5.2 for CO, 12.5 for NO_x, and 0.78 for NMVOCs. For marine vessels consuming either distillate diesel or residual fuel oil the following values, in the same units, except where noted, were employed: 0.03 for CH_4, 0.08 for N_2O, 1.9 for CO, 87 for NO_x, and 0.052 g/MJ for NMVOCs.

Activity data on aircraft fuel consumption were collected from three government agencies. Jet fuel consumed by U.S. flag air carriers for international flight segments was supplied by the Bureau of Transportation Statistics (DOT/BTS 2000). It was assumed that 50 percent of the fuel used by U.S. flagged carriers for international flights—both departing and arriving in the United States—was purchased domestically for flights departing from the United States. In other words, only one-half of the total annual fuel consumption estimate was used in the calculations. Data on jet fuel expenditures by foreign flagged carriers departing U.S. airports was taken from unpublished data collected by the Bureau of Economic Analysis (BEA) under the U.S. Department of Commerce (BEA 2000). Approximate average fuel prices paid by air carriers for aircraft on international flights was taken from DOT/BTS (2000) and used to convert the BEA expenditure data to gallons of fuel consumed. Data on jet fuel expenditures by the U.S. military was supplied by the Office of the Under Secretary of Defense (Environmental Security), U.S. Department of Defense (DoD). Estimates of the percentage of each services' total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Data on fuel delivered to the military within the United States was provided from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2000). Together, the data allow the quantity of fuel used in military international operations to be estimated. Jet fuel densities for each fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 2-36. See Annex H for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 2000). Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by the Defense Energy Support Center (DESC). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 2-37.

Uncertainty

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[53] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Particularly for aviation, the DOT/BTS (2000) international flight segment fuel data used for U.S. flagged carriers does not include smaller air carriers and unfortunately defines flights departing to Canada and some flights to Mexico as domestic instead of international. As

Table 2-36: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990		1995	1996	1997	1998	1999
U.S. Carriers	1,982		2,256	2,329	2,482	2,363	2,638
Foreign Carriers	2,062		2,549	2,629	2,918	2,935	3,305
U.S. Military	862		581	540	496	502	488
Total	**4,905**		**5,385**	**5,497**	**5,895**	**5,799**	**6,431**

Note: Totals may not sum due to independent rounding.

[53] See uncertainty discussions under CO_2 from Fossil Fuel Combustion and Mobile Combustion.

Table 2-37: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	1995	1996	1997	1998	1999
Residual Fuel Oil	4,781	3,495	3,583	3,843	3,974	3,272
Distillate Diesel Fuel & Other	617	573	456	421	627	308
U.S. Military Naval Fuels	522	334	362	477	506	506
Total	**5,920**	**4,402**	**4,402**	**4,740**	**5,107**	**4,085**

Note: Totals may not sum due to independent rounding.

for the BEA (2000) data on foreign flagged carriers, there is some uncertainty as to the average fuel price, and to the completeness of the data. It was also not possible to determine what portion of fuel purchased by foreign carriers at U.S. airports was actually used on domestic flight segments; this error, however, is believed to be small.[54]

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. There are also uncertainties in fuel end-use consumption by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, and aircraft and vessel engine characteristics and fuel efficiencies.

Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. This data may slightly over or under estimate actual total fuel use in aircraft and ships because each service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgements.

Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data which reports fuel used while underway and fuel used while not underway; however, this approach does not capture some voyages which could be classified as domestic.

There is also uncertainty in the methodology used to estimate emissions for 1990 through 1994. These emissions were estimated based on the 1995 values of the original data set and extrapolated back in time based on a closely correlating, but not matching, data set of fuel usage.

The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emissions estimates could be reduced through additional data collection.

Although aggregate fuel consumption data has been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *Revised 1996 IPCC Guidelines* is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO_2.[55] The EPA is developing revised esti-

[54] Although foreign flagged air carriers are prevented from providing domestic flight services in the United States, passengers may be collected from multiple airports before an aircraft actually departs on its international flight segment. Emissions from these earlier domestic flight segments should be classified as domestic, not international, according to the IPCC.

[55] It should be noted that in the EPA's *National Air Pollutant Emissions Trends*, 1900-1999 (EPA 2000), U.S. aviation emission estimates for CO, NOx, and NMVOCs are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates given under Mobile Source Fossil Fuel Combustion overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. EPA (1998) is also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

mates based on this more detailed activity data, and these estimates are to be presented in future inventories.

There is also concern as to the reliability of the existing DOC (2000) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Wood Biomass and Ethanol Consumption

The combustion of biomass fuels—such as wood, charcoal, and wood waste—and biomass-based fuels—such as ethanol from corn and woody crops—generates carbon dioxide (CO_2). However, in the long run the carbon dioxide emitted from biomass consumption does not increase atmospheric carbon dioxide concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass. As a result, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel-based emissions and are not included in the U.S. totals. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for in the Land-Use Change and Forestry chapter.

In 1999, CO_2 emissions due to burning of woody biomass within the industrial and residential/commercial sectors and by electric utilities were about 226.3 Tg CO_2 Eq. (226 Gg) (see Table 2-38 and Table 2-39). As the largest consumer of woody biomass, the industrial sector in 1999 was responsible for 83 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, making up 14 percent of total emissions from woody biomass. The commercial end-use sector and electric utilities accounted for the remainder.

Biomass-derived fuel consumption in the United States consisted mainly of ethanol use in the transportation sector. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles. Ethanol and ethanol blends are believed to burn "cleaner" than gasoline (i.e., lower in NO_x and hydrocarbon emissions), and have been employed in urban areas with poor air quality. However, because ethanol is a hydrocarbon fuel, its combustion emits CO_2.

Table 2-38: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	1995	1996	1997	1998	1999
Industrial	124.8	141.5	144.9	148.6	153.0	188.9
Residential	46.4	47.6	47.5	34.6	30.1	32.3
Commercial	3.0	3.6	3.9	3.8	3.7	4.5
Electric Utility	0.7	0.5	0.7	0.6	0.6	0.6
Total	**174.9**	**193.2**	**197.0**	**187.6**	**187.4**	**226.3**

Note: Totals may not sum due to independent rounding.

Table 2-39: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	1990	1995	1996	1997	1998	1999
Industrial	124,808	141,505	144,881	148,624	152,966	188,915
Residential	46,424	47,622	47,542	34,598	30,123	32,281
Commercial	2,956	3,596	3,899	3,752	3,749	4,526
Electric Utility	673	522	651	612	595	566
Total	**174,862**	**193,245**	**196,973**	**187,585**	**187,433**	**226,287**

Note: Totals may not sum due to independent rounding.

In 1999, the United States consumed an estimated 112 trillion Btus of ethanol. Emissions of CO_2 in 1999 due to ethanol fuel burning were estimated to be approximately 7.8 Tg CO_2 Eq. (7,776 Gg) (see Table 2-40).

Ethanol production dropped sharply in the middle of 1996 because of short corn supplies and high prices. Plant output began to increase toward the end of the growing season, reaching close to normal levels at the end of the year. However, total 1996 ethanol production fell far short of the 1995 level (EIA 1997). Production in 1998 and 1999 returned to normal historic levels.

Methodology

Woody biomass emissions were estimated by converting U.S. consumption data in energy units (17.2 million Btu per short ton) to megagrams (Mg) of dry matter using EIA assumptions. Once consumption data for each sector were converted to megagrams of dry matter, the carbon content of the dry fuel was estimated based on default values of 45 to 50 percent carbon in dry biomass. The amount of carbon released from combustion was estimated using 87 percent for the fraction oxidized (i.e., combustion efficiency). Ethanol consumption data in energy units were also multiplied by a carbon coefficient (18.96 mg C/Btu) to produce carbon emission estimates.

Table 2-40: CO_2 Emissions from Ethanol Consumption

Year	Tg CO_2 Eq.	Gg
1990	5.7	5,701
1995	7.2	7,244
1996	5.1	5,144
1997	6.7	6,731
1998	7.3	7,329
1999	7.8	7,776

Table 2-41: Woody Biomass Consumption by Sector (Trillion Btu)

Year	Industrial	Residential	Commercial	Electric Utility
1990	1,562	581	37	8
1991	1,528	613	39	8
1992	1,593	645	42	8
1993	1,625	548	44	9
1994	1,724	537	45	8
1995	1,771	596	45	7
1996	1,813	595	49	8
1997	1,860	433	47	8
1998	1,914	377	47	7
1999	2,364	404	57	7

Data Sources

Woody biomass consumption data were provided by EIA (2000) (see Table 2-41). Estimates of wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc. that are reported as biomass by EIA. The factor for converting energy units to mass was supplied by EIA (1994). Carbon content and combustion efficiency values were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Emissions from ethanol were estimated using consumption data from EIA (2000) (see Table 2-42). The carbon coefficient used was provided by OTA (1991).

Uncertainty

The fraction oxidized (i.e., combustion efficiency) factor used is believed to under estimate the efficiency of wood combustion processes in the United States. The IPCC emission factor has been used because better data are not yet available. Increasing the combustion efficiency would increase emission estimates. In addition, according to EIA (1994) commercial wood energy use is typically not reported because there are no accurate data sources to provide reliable estimates. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Table 2-42: Ethanol Consumption

Year	Trillion Btu
1990	82
1991	65
1992	78
1993	88
1994	97
1995	104
1996	74
1997	97
1998	105
1999	112